a symposium

edited by

John D. Haun

and

L. W. LeRoy

Subsurface Geology in Petroleum Exploration

SUBSURFACE GEOLOGY
IN
PETROLEUM EXPLORATION

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Colorado School of Mines
Golden, Colorado
1958

Printed and bound by the Johnson Publishing Company
Boulder, Colorado

Engravings by the Colorado Engraving Company
Denver, Colorado

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PREFACE

It is the object of this symposium to acquaint the student, the practicing petroleum geologist, and the petroleum engineer with the tools and techniques used in the search for new oil and gas pools. The various facets of subsurface exploration fall into the following broad categories: analysis of well cuttings, cores, and fluids; well logging methods and interpretation; subsurface stratigraphic and structural interpretation; geophysical and geochemical prospecting; drilling, formation testing, and well completion; subsurface reports; and exploration planning. In executing the objective of the symposium there is, of necessity, some overlap into the areas of surface exploration and production engineering.

This symposium is a logical outgrowth of *Subsurface Geologic Methods* (1st edition, 1949; 2nd edition, 1950) compiled by L. W. LeRoy, which was made possible by the support and interest of many contributors in the petroleum industry. Because of rapid advances and refinements in subsurface geologic methods during the past 8 years, it was deemed necessary to reorganize and compile these new methods in the present volume. This volume will be sold by the Publications Department of the Colorado School of Mines.

Several of the papers that were printed in *Subsurface Geologic Methods* have been included in the present symposium with little or no revision; other papers from the former volume have been considerably revised in the light of recent developments in the particular field being considered. Some subjects treated in the former volume, namely those concerning mining methods and "hardrock" geology, have been dropped from the present compilation because of the change in primary objective. Many new subjects, not included in the former volume, have been added. It is hoped that these papers will be of value to geologists and petroleum engineers in the field as well as to educational institutions that offer formal courses in subsurface geology and petroleum geology.

The editors wish to thank the contributors to this symposium, without whose interest it would have been a much more difficult task. We would also like to acknowledge gratefully the assistance received from George W. Johnson, Professor of English at the Colorado School of Mines, for his many editorial suggestions. Special thanks go to Roger Hull, Hendrietta Jenson, and Doris Graham, of the Colorado School of Mines Publications Department, for their diligent work on this volume. We wish to extend our appreciation to John W Vanderwilt, President of the Colorado School of Mines, for his support of this symposium.

John D. Haun
L. W. LeRoy

Colorado School of Mines
Golden, Colorado
June 1, 1958

Part One INTRODUCTION

Chapter 1

TRAINING THE PETROLEUM GEOLOGIST

John D. Haun

The primary objective of the petroleum geologist is to discover petroleum. This objective seems so obvious that it should not have to be stated. As a matter of fact, many petroleum geologists have lost sight of this major reason for their existence.

Many factors contribute to the success of an exploratory effort. Among these factors are the basic training of the geologist, the personnel and organizational framework of the company with which the geologist works, and perhaps most important, the facility with which the geologist is able to think independently and imaginatively. Charles F. Kettering often has said that the inventive ability of many young men has been weakened seriously by the rigidity of our present educational system. If this opinion is true, then we should endeavor to provide an educational atmosphere that will keep alive the innate curiosity, the excitement of new horizons, which is a part of nearly every young man in early childhood. Such an atmosphere is becoming more difficult to attain as our technology advances in complexity and requires an ever-increasing amount of time for mastery.

TRAINING

This symposium is an effort to bring up-to-date many of the tools and techniques with which the subsurface geologist must be familiar if he is to be successful in the geological profession. More important than the learning and mastery of subsurface techniques, however, is the basic training of the geologist. A framework of knowledge in which these specific techniques are applied should include a thorough grounding in the physical processes of geology, the sequence of events of geologic history, the elements of structural geology, the significance of the paleontologic record, the principles of stratigraphy, the processes of sedimentation, and the principles of petroleum geology. Concurrent with the study of these branches of geology should be course work in crystallography, mineralogy, and petrology. The advanced student of geology should also be well-trained in the various techniques of field mapping and measurement of stratigraphic sections. There is an increasing necessity for a better grounding in mathematics, physics, and chemistry. The ability to write a concise geological report and to present a clear, well-organized oral report are necessary if the geologist is to sell his ideas to the men with whom he works. Further ramifications of the various areas of training and the part that these areas play in the work of the petroleum geologist will be considered.

Physical Geology

Thanks to the Huttonian concept, we are able to gain more understanding of the processes of erosion, deposition, and deformation that were in effect in past geologic time by a study of these same processes that are reshaping the earth's surface today. The more complete the knowledge of the petroleum geologist of weathering processes, the movements of surface and subsurface waters, the depositional environments of lakes, swamps, and oceans, the better will be his interpretation of the nature and lateral extent of the various rock types encountered in both surface and subsurface studies.

Historical Geology

The geologic history of a petroleum province holds the key to the origin, primary and secondary migration, and entrapment of the petroleum of that province. The knowledge of the geologic history of a closely drilled area is also an aid in the prediction of petroleum occurrences in a less developed nearby area which may have had a similar history. The student's knowledge of the geologic history of the various continents and broad subdivisions of the continents provides a frame of reference into which more detailed analyses of a provincial nature may be coordinated. In specific petroleum prospects, the changes in structural configuration that have taken place in recent geologic time should be separated, if possible, from the structural conditions that existed during earlier stages of geologic time.

Paleontology

In addition to the more obvious uses of paleontology in petroleum exploration, such as age determination and regional correlation, branches of paleontology, especially micropaleontology, have been perfected as tools for the petroleum geologist. In the Gulf Coast, in California, and in Indonesia, species of foraminifera are used in structural contouring and in detailed local correlation. During the past 10 years, considerable advances have been made in the usage of fossils for determining sedimentary environments that are, in turn, related to the study of source beds for petroleum and to the more complete understanding of reservoir rocks.

Structural Geology

Probably the most important facet of the geologic science used by the petroleum geologist is structural geology. A student must be versed thoroughly in the classification of folds and faults and in the types of local and regional forces that account for their development. The student also must be well acquainted with the methods of construction of maps and cross sections that are used to depict structural configuration in three dimensions. The part played by various logging and geophysical techniques in assembling structural data should be a part of the training of the petroleum geologist, either in school or in the early years of professional work.

Stratigraphy and Sedimentation

The increasing importance of petroleum accumulations that are controlled in large part by stratigraphic factors has brought into greater focus the necessity for an understanding of the basic principles of stratigraphy and sedimentation. Here again, the methods of collecting data in the field and in the subsurface and the manner in which these data may be depicted on maps, as well as the significance of the data, should be made a part of every geologist's knowledge. An effort also should be made to acquaint the student with regional and systematic stratigraphy in order to instill a clearer understanding of the interrelationships between historical geology, structural geology, and stratigraphy. Petroleum exploration, from a strictly geological viewpoint, is primarily the application of the principles of stratigraphy and structural geology.

Mineralogy and Petrology

The mineralogy of the grains, interstitial matter, and cement of detrital rocks can play a direct part in the migration and entrapment of petroleum. There is often a correlation between the mineralogy of chemically precipitated rocks and areas of high porosity and permeability. A knowledge of source areas and diagenesis is necessary to the complete understanding of the stratigraphy of sedimentary rocks; this knowledge then may be used in the delineation of areas and formations that are more favorable for the entrapment of petroleum. The techniques of optical mineralogy and petrography are sometimes necessary to the solution of problems of correlation as well as problems of origin and diagenesis of sedimentary rocks.

Field Geology

Despite the recent downgrading of field geology by some educators and the lack of structural expression on the surface of some parts of the world, the fact remains that instruction in field geology is *one of the most important phases* of training for the geologist. It has been said that there is nothing more sobering than an outcrop. If the student has not been trained in the solution of structural problems in the field, he will find much more difficulty in visualizing three-dimensional complexities on the drafting board in the office. Field training develops observational powers and deepens understanding of the magnitude and nature of geologic problems. A background of field training is absolutely essential to a complete appreciation of the science of geology and to the most logical solution of many complex subsurface problems.

To the general training in field mapping procedures and in the measurement of stratigraphic sections, some instruction in surveying and photogeology should be added. Photogeology recently has gained importance as a tool of the petroleum geologist. It is quite obvious that the most logical interpretation of the geology on photographs in the office can be made by a geologist who has had considerable experience in field mapping.

Mathematics, Physics, and Chemistry

Many geologists are striving to make their science more precise than it has been in the past. In order to bring this about, a more thorough understanding must be gained of the forces and processes that bring into being, and that react upon, the rocks of the earth's crust. Many of the basic problems of petroleum geology such as the origin of petroleum and the mechanics of migration of petroleum can be attacked only in the light of the physical and chemical principles that bear on the problems. Rather glaring errors in reasoning have been made by geologists who have tried to answer some of these problems without adequate knowledge of the basic sciences. The more common problems facing the petroleum geologist—such as the interpretation of electric logs and drill-stem tests; cementation, solution and recrystallization phenomena; and variations in salinity of subsurface waters—are understood more readily if the geologist has a working knowledge of areas of chemistry and physics that relate to these problems.

Course work in the aforementioned branches of geology and allied sciences, plus course work in the humanities or liberal arts (English, foreign languages, history, political science, etc.), should form the program of undergraduate study leading to the profession of petroleum geology. As in the other science departments, geology departments are increasingly faced with the problem of turning out graduates skilled in the complex technology of their profession and concurrently turning out "well-rounded" graduates who are prepared to face their responsibilities as world citizens.

The training of the petroleum geologist does not end with the granting of an academic degree. Many companies maintain formal six-month to two-year training programs that are designed to round out the new employee's general education in geology and to acquaint him with company organization and objectives. In addition, it is the responsibility of the geologist throughout his career to become acquainted with the geology of the area in which he is working and to keep abreast of new concepts and advancements in geologic science. In a sense, the new graduate's training in geology has just begun. There is a constant overlap between the training and the duties of the petroleum geologist.

DUTIES

Two probable channels into which the duties of young petroleum geologists will be directed are field mapping and/or well sitting. For the adequately trained geologist, field work will not be new, but the specific company-approved techniques must be mastered. The duties of a well-site geologist are primarily sample and core examination, selection of coring and testing intervals, recommendations regarding the mud program, logging, and completion methods.

The end product of most company assignments is a report, which may consist of a sample log and a written description of the samples and cores obtained from a wildcat well, or it may consist of a map and a written description of the structural geology and stratigraphy of an area and an estimation of the possibilities of petroleum entrapment. Wildcat prospect reports will contain information regarding depths to possible pay horizons, thickness of formations that will be encountered, distances from nearby production, gravity of oil expected, accessibility of drill site, and water availability. In addition, information may be required regarding distance from piplines, price of oil, land acquisition, and drilling costs.

From field and well-site duties, it is only a short step to the compilation of local or regional structural maps and formation correlations. In addition to the stratigraphic and structural work, the geologist may be required to keep abreast of the activities of other companies in a particular area (leasing, geophysical activities, wildcat locations, etc.).

As a geologist advances in a company, he will become involved with exploration planning, budgeting problems, hiring and coordinating personnel, and myriad administrative duties. The geologist's day-to-day problems tend to divert his mind from his basic duty and responsibility to his company: *finding more* *oil.* Ultimately, the geologist must contribute his share to the teamwork that brings about the discovery of a new field; this contribution will justify his existence as a petroleum geologist. Of all the characteristics that are desirable in an exploration geologist, the one most likely to contribute to the discovery of new fields is imagination tempered by sound reasoning, and this quality may be as much an inherent trait as an acquired skill.

Chapter 2

THE FUTURE OF SUBSURFACE PETROLEUM EXPLORATION

A. I. Levorsen

The usefulness of subsurface geological methods in petroleum exploration and production problems has increased steadily since the beginning of the petroleum industry. As more subsurface understanding is called for, more and more geologists become specialized in this type of work, until in many areas practically all of the exploration geology is based on subsurface interpretations.

PETROLEUM EXPLORATION

Petroleum exploration in most regions has followed a logical sequence in that it has proceeded from the known and obvious to the less known and less obvious, from surface geology toward subsurface geology. Once the anticlinal theory of oil and gas accumulation was accepted, it was only natural that all anticlines that could be observed at the surface should be mapped and tested by the drill. This was followed by structure mapping at shallow depths by core drilling, by subsurface mapping within the reach of the drill, and at all depths by geophysical methods. The search for structural traps may be called Phase I in the orderly sequence of exploration.

As favorable closed structures in a region become increasingly difficult to locate by any available means, attention is directed to traps in which local structure is but a part of the reason for a trap, the other part being some stratigraphic anomaly that combines with the structure to form the trap. It is in this phase, or Phase II of the sequence, that half domes, open anticlines, terraces, noses, and any irregularity in the regional dip become important, because such structure, combined with any one of the many kinds of stratigraphic anomalies, may form one of a wide variety of traps in which oil and gas pools have accumulated.

The stratigraphic evidence for Phase II develops only as wells are drilled and logs and subsurface data become available. Consequently most of the drilling for stratigraphic traps is close to wells that have tested the crests of dome folds, for it is only there that stratigraphic information is available by which combination traps can be predicted. It is around the flanks of dome folds, moreover, that arching or half domes occur down the pericline so that half of the trap is known; then it becomes necessary to locate only the other half—the stratigraphic half—of the combination.

For several reasons wells are sometimes drilled and pools discovered where there is no local structure. One reason is that an error has been made in the structural mapping, and no local fold or fault occurs where it is mapped. Another is that a permeable lens or reef is suspected. Leasing problems cause many wells to be drilled without regard to structure, as for example where leases are about to expire and no definite geological information can be worked out to evaluate the lease even though the location is generally favorable. Large lease ownerships, likewise, may justify drilling random wildcat wells to satisfy lease requirements or to gain the stratigraphic information needed to proceed with the exploration program. Each of such wells, even though nonproductive, adds subsurface data that can be integrated with other data to work out combination trap prospects or purely stratigraphic traps.

Finally, after all structural anomalies that combine with stratigraphic features to form traps have been tested, the purely stratigraphic traps remain. This may be called Phase III. These traps require little or no local structural anomaly to complete the trap and consist of such phenomena as sand patches and lenses; shoestring, channel, and bar sands; coquina lenses; dolomitization patches; irregularities along an up-dip wedge-out of permeability; variations in the permeability; and a variety of permeable lenses surrounded by impermeable rocks. Pools of this kind are discovered either by random drilling or by drilling based on interpretations of precise subsurface stratigraphic data.

The three phases and the kind of mapping called for may be listed as:

Phase I—Structural traps. Surface, subsurface, and geophysical mapping.
Phase II—Combination traps. Subsurface and geophysical mapping.
Phase III—Stratigraphic traps. Subsurface mapping.

A sequence such as this does not have sharp time boundaries, and all three phases may be operating to a varying degree in every region simultaneously. Each phase, however, is seen dominating the exploration effort at some time during the life of nearly all regions, and generally in the order listed above. Different companies and different geologists, each with a different background of training and experience, will attack the exploration of a region differently, and some phase may be omitted. If there are no outcrops, for example, surface mapping may be omitted, and geophysical mapping may begin at once. If a purely stratigraphic trap-pool is discovered early, more attention will be given to stratigraphic exploration in the early stages. On the whole, however, the more exploration there has been, the higher will be the proportion of effort devoted to subsurface mapping, both structural and stratigraphic.

SUBSURFACE GEOLOGY Subsurface geology increases in usefulness as more drilling is done in a region principally because (1) the more exploration there has been the more difficult it is to find new structural features to drill, and more attention is given to stratigraphic anomalies that can be determined only by subsurface mapping, and (2) the more exploration, the more data there are available for study and comparison with past data.

The emphasis in subsurface geology changes with time. As the exploration of any region develops, more attention is given to subsurface methods for mapping structure than is given to surface and geophysical techniques. Once a structure is located and mapped, there is seldom a need for complete remapping. The emphasis then shifts to any of a variety of stratigraphic features associated with the structure that might form traps, and these require a revaluation as every new log in the vicinity becomes available. Finally, an accurate understanding of the geologic history of a region calls for mapping every imaginable phenomena and episode that can be located until the history is unravelled.

There is also a need for subsurface geology during the development of a pool. The subsurface geologist is accustomed to working with all kinds of well logs and well data, and his interpretations and thinking are essential to the petroleum engineer's understanding of the geological conditions associated with the reservoir. After all, much of the development and production of a pool are but extensions of principles that the geologist uses in his daily thinking during the search for a pool.

The well log is the basic source of information in subsurface mapping. Significant and useful facts are continually being squeezed out of the old logs, and development of new ways of logging are almost an annual occurrence. No area has been mapped completely until the most modern logging methods have been applied to it. Even where the logs are old, one modern log may help considerably in deciphering the old log. The sample log, the paleontologic log, the time log, the electric log, and the continuous-velocity log add new data to the stratigraphic record. These data, after being evaluated, can be applied frequently to the drillers' logs to make them more useful than before.

All analyses of stratigraphic methods in exploration point to the increasing need of greater precision. The direction is toward better logs; more accurate correlations, contacts, facies changes, unconformities, and truncations; to more data on porosities and permeabilities; and to better fluid and reservoir characteristics such as saturations, pressures, and temperatures.

The relationships between structural and stratigraphic phenomena in the formation of a trap are shown in Figure 2-1. The gradation from 100 percent structural causes to 100 percent stratigraphic causes is shown diagramatically.

THE SUBSURFACE GEOLOGIST

The first objective of the petroleum geologist is to discover oil and gas; this is the chief reason for his existence. As long, then, as there is a need for more petroleum discoveries, there will be a need for the petroleum geologist—first for his ability to work geology at the surface, then, and probably more important, his ability to work geology below the surface.

Subsurface geology, like other kinds of geology, is dynamic. New ways are continually being found for obtaining subsurface information, or interpreting data, and for predicting the position of a favorable prospect. The subsurface geologist must, therefore, be alert to change and be ready to use new kinds of information, to re-examine his old data for new meanings, and to put his findings together in new ways. Not only are new techniques continually being discovered but, once discovered and found to be practical, there is a steady advance in their interpretation and in the construction and operation of the equipment.

Geophysical surveys are an integral part of any modern exploration program. A geophysical survey is, in fact, a subsurface geological survey conducted from the surface without drilling. The records might be thought of as logs of the rocks below the surface, and they require geological interpretation exactly as do well logs. It is essential that any geologist working on subsurface problems should be familiar with the advantages and the limitations of the different geophysical methods of surveying.

Geophysical data should be fitted into other subsurface data and all of the information synthesized into a complete picture. This procedure becomes more and more important as the structural closure diminishes, for less and less reliability can be placed on minor structural features, especially where the measurements are near or below the limits of error of the instruments, and more and more reliance must be placed on stratigraphic anomalies. Geophysical surveys of all kinds are steadily improving in accuracy, however, and areas that could not be precisely mapped even in the recent past may suddenly become mappable.

One corollary of an increase in subsurface mapping is that it requires more geological imagination than surface or geophysical methods. The reason is that the data are frequently widely scattered, insufficient, or inconclusive; and unless

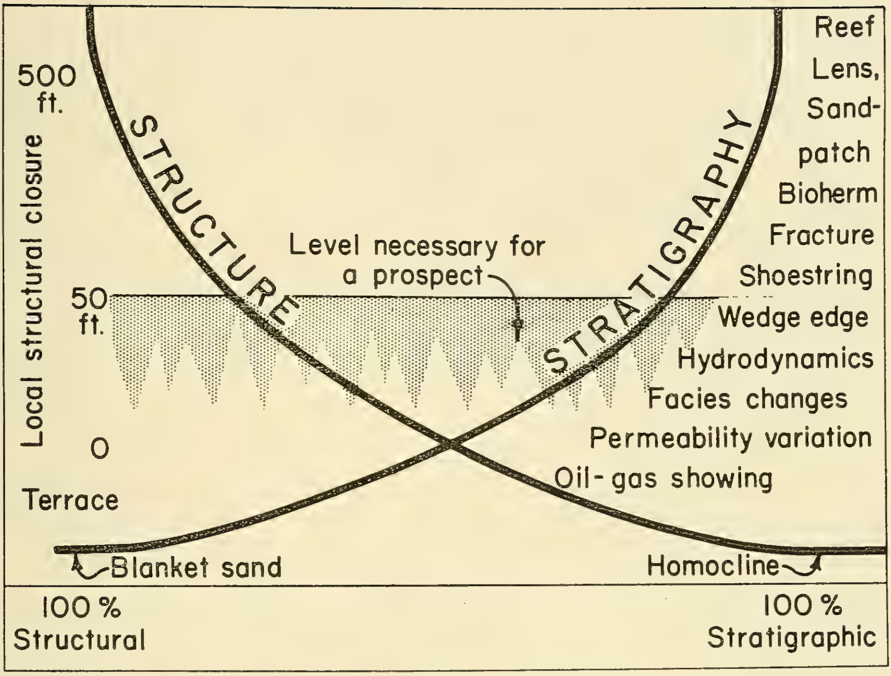

FIGURE 2-1. Composition of a prospect. Structure alone may form a prospect where there is a blanket sand plus 10 to 15 feet or more of structural closure. Where less closure is present, then such features as showings of oil and gas, permeability variations, facies changes, hydrodynamics, or wedge edges of permeability are necessary to combine with the structure to form a trap. Where there is no structural closure, then some stratigraphic features alone such as shoestring sands, fracture porosity, bioherms or reefs, and sand patches, may form traps.

the geologist fills in the gaps by use of his imagination, no prospect will develop. Because data are frequently inadequate, the data that are available should be as precise and accurate as possible.

When one considers that tens or hundreds of geologists are examining the same data and trying to find a clue for a drilling prospect, one realizes that discovering a prospect requires dependable data, clear thought, and an active imagination. Exploration in almost every district is continually at the fringes of the knowledge of the district. Any obvious prospects would have been drilled. A new prospect, consequently, must usually be developed in a place others have rejected or overlooked. As a result, the subsurface geologist's work is in intensive competition with all others in the same district.

An expanding future of subsurface mapping seems assured for as long a time as there is a need of discovery and production of oil and gas. Not only are subsurface methods essential, but their usefulness increases as it becomes more difficult to find traps by surface and geophysical methods. The trend so far in subsurface work has been toward more precise measurements of many kinds of geologic data, a wider variety and many more maps on which to consider the data, and the inclusion of more and more variables in the geologist's thinking.

Part 2

ANALYSIS OF WELL CUTTINGS, CORES, AND FLUIDS

Chapter 3 EXAMINATION OF WELL CUTTINGS

Julian W. Low

INTRODUCTION

A few years ago the principal work of the oil geologist consisted in finding and mapping a surface geologic structure by means of the plane table and measuring a surface stratigraphic section. If wells had been drilled in the immediate vicinity, samples were examined in a cursory fashion for the purpose of estimating the depths to objective horizons. Many of the wells were drilled without benefit of geologic appraisal of the area, and no representative samples were saved for later study. Little or no thought was given to subsurface work as a principal tool of exploration.

Today, the petroleum geologists of most regions are concerned primarily with subsurface geology and the main source of subsurface geologic data—well samples and cores. The quality of well cuttings has steadily improved as a result of better drilling practices, and this development has encouraged a greater emphasis on subsurface methods. The geomicroscopist now occupies a foremost position in the search for new oil fields. Surface field geology still maintains an important position, but it is now often used as a supplement to the more highly regarded subsurface geology.

The man working with well samples is constantly confronted with two problems which largely govern his daily activities. They are quality of work and quantity of production. In petroleum geology these two factors must be kept in proper balance with the requirements of the exploration program. The emphasis on one or the other changes from time to time because of the shifting scenes of exploratory activities and the evolution of ideas on petroleum geology. The subsurface geologist must exhibit a high degree of flexibility in the application of his geologic knowledge if he is to keep abreast of the advances that are being made in the science. In order to meet the demands of the day, the microscopist must do more and better work than has been required in the past. The methods employed should be consistently accurate within the limitations of the instruments, yet rapid enough to turn out the necessary volume of work.

The purpose of this chapter is to make available to the beginning microscopist the methods that have been successful in the course of many years of application in oil geology. The attempt is to present only one phase of subsurface work—lithologic determination of well samples by means of the low-power binocular microscope, the present work horse of the oil companies.

Rotary Well Cuttings

In the process of drilling a well with rotary tools, drilling fluid (mud) is pumped down the inside of the drill pipe, thence through vents in the bit into the space (annulus) between the drill pipe and the wall of the hole and up to the surface again. The chips of rock cut by the bit on the bottom of the hole are picked up by this constantly flowing mud stream and are carried to the surface, where they are collected, washed, and put in envelopes for later examination.

If the viscosity and other desirable properties of the mud are inadequate, considerable mixing of the cuttings occurs during transportation up the hole. Another function of the drilling fluid is that of preventing caving and sloughing from the wall of the hole during drilling operations. Caving is prevented by the formation of a thin filter cake, composed of the solids in the drilling fluid, which accumulates on the exposed walls at porous and permeable horizons, together with the outward pressure exerted by the column of fluid in the hole. When drilling mud fails to form an effective filter cake, soft formations absorb large quantities of water, which causes them to swell and loosen and slough into the upward-flowing mud stream. These cavings mix with the returning fresh cuttings from the bottom of the hole and are collected and preserved with the sample caught at the surface. At the surface the mud is often directed through a series of settling pits where the chips fall to the bottom, and the mud is circulated back into the hole. Occasionally the mud pits are jetted violently in order to keep the solids thoroughly mixed, but in this process the cuttings are also disturbed and some are picked up by the pumps and recirculated into the hole. These old cuttings mix with those freshly cut at the bottom of the hole and reappear in the next sample.

Chips cut from the bottom of the hole usually range from 1/8 inch to 5/8 inch across and are normally flaky in shape. The sizes of the chips depend on the character of the rock, the sharpness and type of the bit, the rate of bit rotation, and the weight on the bit. Unless the rock is extremely soft, such as chalk or some shales, the chips are quite angular. The cuttings from any given lithology tend to be of rather uniform size.

In contrast to fresh cuttings, cavings may occur in pieces as large as two inches. Since caving is more likely to develop in the softer rocks, the caved fragments are often well-rounded. Recirculated material, if soft, will be very well-rounded; but if the material happens to be from resistant rocks, it may be very difficult to distinguish from the fresh cuttings.

Depth Lag of Samples

When samples are caught at the surface, the depth of the hole is recorded on the bag. This depth is measured from either the top of the derrick floor or from the top of the rotary table. While the hole is shallow, there is little discrepancy between the recorded depth and the actual position from which the sample was cut. As the hole deepens the error not only becomes larger but also is subject to considerable variation, according to the rate of drilling and the rate of mud circulation. The two examples given below illustrate how the rate of drilling affects the lag.

1. Assume that at a depth of 6500 feet it requires 30 minutes for cuttings to travel from the bottom of the hole to the surface, where they are caught. The drilling rate is 20 feet per hour. Therefore, while a chip is traveling to the surface, the bit drills to 6510 feet. Although the depth recorded on the sample bag is 6510 feet, the lowest sample recovered is actually from a depth of 6500 feet. The lag in this case is 10 feet.
2. At 6510 feet a hard, slow-drilling stratum is encountered, and the drilling rate falls to 4 feet per hour. Cuttings from this rock reach the surface when the bit is at 6512 feet. The lag here is only two feet.

It is evident that a lag factor cannot be applied to sample depths solely on the basis of the depth of the well, except where the rocks being penetrated are very uniform in drilling characteristics. In order to make lag adjustments correctly, it is necessary to know the rate of drilling and the rate of mud circulation. These data usually can be obtained from the drilling record of the well. Inasmuch as these records are not ordinarily available to the microscopist, it is better that he plot on the log the lithologies at depths shown on the sample bags even though it is known that some lag exists. If the necessary data become available subsequently, the corrected tops of main stratigraphic units can be noted on the log strip.

Sometimes it is important to ascertain the actual depth from which a sample comes, as, for example, when a show of oil is observed. In this case the bit is lifted slightly off bottom, but rotation of the drill pipe and circulation of the drilling mud are continued. Cuttings already in the mud column are thus brought to the surface though no additional hole is cut. The last chips to reach the surface are from the bottom of the hole. When the bit is again lowered and drilling resumed, the first chips to come over the top are from the circulated depth and slightly below. Samples marked "Cir. 30 min." or "Cir. 1 hr." refer to the process just described.

When a bit is to be replaced, it is necessary to shut down the mud pumps and pull the drill pipe out of the hole. This procedure may require several hours. A new bit is attached, and the drill pipe is made up and run back into the hole. The process is called making a trip. When making a trip, and for some time after one is made, there may be an excessive amount of caving into the hole. Therefore, it is to the advantage of the microscopist, when drilling records are available, to indicate on the log strip where trips were made so that he will be prepared in advance for extraneous materials in the samples.

Cable-Tool Cuttings

A cable-tool string consists of a cylindrical bit with a chisel-like cutting end, a sliding steel linkage called jars, a drill stem somewhat smaller in diameter than the bit and several feet long, and a steel wire rope or drill line from which the entire assemblage is suspended. The other end of the drilling line is attached to a heavy walking beam on the drilling rig. This beam rocks up and down when power is applied, and in so doing lifts the tool string up several feet and then allows it to fall back to the bottom of the hole, where the chisel end of the bit chips away the solid rock. A slight torque taken in the drilling line causes the bit to rotate slowly with each stroke of the tool string.

Cuttings are removed with a bailer, which is a steel pipe from 10 to 30 feet long. A gravity-operated valve at the bottom opens or closes according to the driller's manipulation of the suspending line.

Before drilling is begun, a bailer of water is lowered and dumped into the well. The bit is then run in, and the churning operation just described is begun. When several feet of new hole have been cut and the softer portions of the formations have made a thin mud, the bailer is again run into the hole to remove the mud and drilled chips. A portion of the mud is caught at the surface in a sample box or bucket, the cuttings are recovered, washed and dried, and placed in bags numbered with appropriate depths.

Cable-tool cuttings are usually much finer than the samples from rotary holes. Even if large pieces are chipped out by the bit, the repeated churning continues to break them into finer particles.

Although rotary holes are taken to great depths with little or no casing, cable-tool holes must be cased frequently to prevent collapse of the walls. For this reason, cavings from high up the hole are more common in rotary samples. On the other hand, cavings which do occur in the cable-tool hole fall to the bottom where they are ground and thoroughly mixed with the fresh cuttings so that they are more difficult to distinguish.

The depths are more accurate in cable-tool samples because there is no lag in the time between cutting and sampling. However, due to their fineness, they are more difficult to interpret.

Appraisal of Well Samples

It has been shown that the quality of well samples varies appreciably, and that the microscopist is faced at the outset of his work with the problems of depths and distinguishing between representative cuttings and cavings. There is no adequate substitute for experience in judging well samples. The suggestions listed below should help the novice avoid certain common errors.

1. Always be suspicious of large pieces of rock in the sample, regardless of whether they are angular or well-rounded. The shape is not always indicative of cavings, but the large sizes generally are. If the piece did come from the bottom of the hole, then there should also be a good representation of the same lithology in the finer materials.
2. Compare the lithologies determined from the samples with the interpretive lithologies of the electric log or radioactivity log. These logs are particularly helpful in sections of sands and shales or evaporites.
3. If possible, become familiar with the lithologies of the formations in the area by reviewing existing descriptions of nearby wells and surface sections.
4. Consider the probability of caving from formations examined higher up in the hole. Shales, anhydrite, gypsum, fractured limestone, friable sandstone, and residual or detrital cherts are more liable to cave than well-indurated beds.
5. When caving is suspected, review the descriptions of similar rocks logged up the hole. It may be advisable to compare the cuttings with those previously run.

Preparation of Samples for Examination

Sometimes the samples in the bags are in poor condition for microscopic examination, and the microscopist must do a certain amount of reconditioning before starting the microscopic work.

Coarse and fine materials can be separated as the samples are run by a process called dry panning. First, spread the sample in the scoop tray. Tilt the tray slightly and, while holding it in this position, knock the edge of the tray lightly against the knuckles of the other hand until the cuttings accumulate in the end of the tray. The fine fraction will be on the bottom and the coarse pieces on top. Now reverse the tilt of the tray and knock it sharply a few times. The coarse pieces will roll toward the other end, leaving a trail of the fines behind. Much or all of this coarse material may be cavings, and the fine chips are now segregated for examination. This process of segregating the coarse and fine fractions requires but a few seconds.

Samples are sometimes contaminated with steel shavings off the drill bit. In some instances the steel shavings may constitute a substantial proportion of the sample, making it difficult to study the cuttings. To remove the shavings, first place a sheet of paper over the cuttings, which have been spread evenly in the tray, and then pass a small magnet over the paper. The shavings will cling tightly to the under side of the paper. Lift the paper and magnet together as a unit to remove the shavings. When the magnet is lifted, the shavings fall and leave the magnet clean.

When samples are improperly washed, very fine clays, powdered limestone, or dried drilling mud forms a fine dust which adheres tightly to the chips. It is impossible to make a reliable determination of samples in this condition. It may be necessary to rewash the samples, but as a rule washing facilities are not available. The next best thing to do is winnow the sample in front of an electric fan. Make a cursory examination of the cuttings to ascertain that there is no essential fine fraction that might be lost. Place the fan on a large piece of paper, such as a newspaper. Now rub the sample between the palms of the hands directly in front of the fan, allowing the chips to fall slowly through the air stream to the paper. The coarse material will fall near the fan, the fine portion farther away. Very fine dust is blown out into the air and does not fall on the paper.

A technique often employed in micropaleontological work, and having definite advantages in some lithologic work, is that of examining the samples while completely immersed in water. This method is good when the samples are dusty, as described in the preceding paragraph.

A black plastic dish ½ inch deep and 3 to 4 inches in diameter is substituted for the scoop tray. The sample is spread evenly over the bottom, and enough water is added to cover the chips completely.

The advantages of this procedure are (1) the effects of dusty or pulverized materials on the chip are eliminated, (2) fine details of the rock are sharply defined, and (3) colors are more vivid. The disadvantages are (1) it is slow and dirty work, (2) the samples must be dried before replacement in the envelopes, (3) the tones of gray shales are deepened until subtle differences are difficult to distinguish, and (4) acid reactions are unreliable with wet chips.

The immersion technique is applicable to field use where samples obtained from the drilling well must be examined immediately while still wet. Wet samples that are not immersed in water are difficult to analyze.

Microscopic Magnification

The magnification of the binocular microscope ranges from about 6× to about 90×. In the instruments used by most oil companies the upper magnification limit is about 36×. With ordinary two-tube fluorescent lamps for illumination, the maximum effective power is about 18×, though most work is done at powers ranging from 6× to 12×. Higher powers are used only at the sacrifice of breadth of field and proper illumination.

It is important to decide at the beginning of the project the magnification and illumination that will be used and then to make an effort to maintain these conditions. Consistent interpretation and graphic representation is impossible if the conditions under which the work is done are varied from time to time.

Under a 9× combination of lenses, particles of 0.05 millimeter diameter are distinctly visible. This magnification is quite satisfactory for most sample work. Occasionally it is necessary to use higher powers for the determination of lithologic details, but unless there is a special reason, high powers should be avoided.

Four good reasons for using the lowest power that will permit observing the essential details of the rocks are (1) wider field of vision, (2) minimum of eyestrain, (3) relatively higher illumination of the sample, and (4) greater depth of focus.

Illumination

When the log is plotted concurrently with the sample examination, it is highly important to provide adequate lighting for the log strip. Microscopists seem to be in agreement that log plotting causes more eyestrain than does the microscopic work. Proper lighting of the log must not be neglected.

The two-tube fluorescent lamp is a popular type for low-power binocular work. Although these lamps can be obtained in a number of models, the most convenient one is a flexible—or jointed—stand drafting lamp that can be clamped on the back side of the microscope table, thus leaving the table top around the log and microscope free of obstructions. Such a lamp with 18-inch tubes provides adequate light for both the microscope and the log. A narrow shade on the top protects the eyes from direct rays of light. Experience has shown that subtle shades of color are brought out best when one of the fluorescent tubes is blue-white and the other is flesh colored—the so-called daylight tube. Pale tints of color in the rocks tend to wash out in the blue-white light, and they assume a yellow cast when only the daylight tube is used.

There are numerous types of focused stage lights, some of which are satisfactory for well-sample work. However, when these lights are used, it is necessary to provide additional lighting for the log strip.

Accessories and Materials

The following check list of materials and accessories is to aid in the preparations for running samples.

TABLE 3-I

Inks—black, red, and blue (waterproof).
Pencils—2H, 4H, and 8H.
Pen and holder—Hunt No. 104.
Cloth pen wiper.
Erasers—Pink Pearl, Ruby.
Plotting templet—to be made as shown in Figure 3-1.
Artist charcoal-blending stumps 3/8 in. dia. 6 in. length.
Sandpaper—No. 0 and 1, for sharpening stumps.
Magnet—small horseshoe.
Small knife.
Steel teasing needle.
Forceps—pointed, steel.
Acid dish—glass furniture leg coaster.
Scotch drafting tape.
Dennison cloth tape (1¾ or 2 in.).
½ millimeter grid. This grid can be made by photographic reduction of millimeter cross-section paper. The grid is cemented to the bottom of the scoop tray.

Colored Pencils
(Mongol Indelible)

Color	*Number*
Yellow	867
Blue	845
Red	866
Green	848
Green	888
Orange	862
Brown	813
Brown	853
Purple	844

The last two digits are the number of the color; the first is the pencil shape; i.e., numbers 767, 867, and 967 are the same color.

Synthetic lacquer (model plane "dope").
Lacquer thinner.
Artist bristle brush—½ in., flat.
Scoop tray—made from sheet aluminum as shown in Figure 3-2.

EXAMINATION OF WELL SAMPLES

The importance of accurate well-sample determination and specific descriptions of the lithologies can hardly be over-emphasized. It is basic geologic work—the foundation on which will rest the entire structure of subsurface investigation. This structure, like any other, cannot be stronger than its foundation. Microscopic sample determination is exacting, though not exact. The materials with which the microscopist must work are subject to differing interpretations, and it is invariably the careful and discerning worker who will interpret correctly. The microscopist is very much on his own, and the work of many others who use his logs depends on the reliability of his determinations. As will be seen, many of his methods and tools are not precise, and the accuracy of his work will depend largely on how well he applies them. The geologist who runs samples should regard the lithologies he observes in the light of his knowledge of the processes of sedimentation. He should frequently ask himself how and why. Why was this kind of rock formed and how was it formed? What were the physical, chemical, and biological conditions that produced the rock? Many of the answers are evident in the chips from wells. The geologist-microscopist is not merely a laboratory technician, unless, because of his own lack of geological thinking and application, he reduces himself to that status. He is first and last a geologist, and he is expected to do the work of

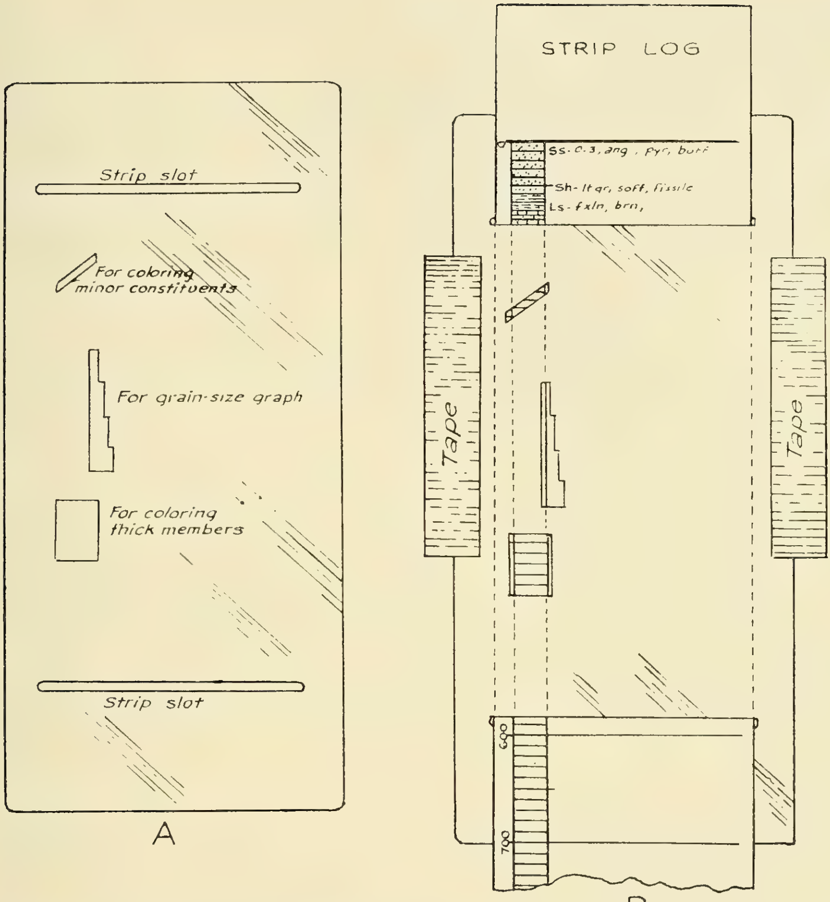

FIGURE 3-1. *A*—Plotting templet. Cellulose acetate 0.015 to 0.020-inch thick. Slots cut with knife along straight-edge, using a log strip as a pattern. *B*—Templet with strip inserted and taped to top of table.

a geologist. The microscope is only one of many tools of his profession. He must use this, as other tools, in a professional manner. Sample determinations are a means to an end, but not an end.

The methods employed in making lithologic strip logs vary greatly among companies and individuals. Some of the methods in daily use are not good for one reason or another. The methods given here may not be the best, but they have been tested for a number of years and have been found satisfactory.

Coarse Clastic Rocks

(Plotted in canary yellow)

This group of rocks consists of gravels, conglomerates, sands, and sandstones. Grain sizes range downward to 0.1 millimeter, and the grains may be of any noncarbonate material. In describing the coarse clastic rocks, one should consider the following characteristics:

1. *Grain Size:* Grain sizes should be determined to the nearest 0.1 millimeter. Record the weighted average size. In cases where the largest grains are much larger than the weighted average, record also the maximum size of the grains.

2. *Grain Shape:* There is an almost infinite number of variations in the shapes of sand grains, but for the sake of simplicity and consistent recognition, only 5 general classes are considered. These typical shapes are shown, in Figure 3-3 and may be defined as follows:

SHARP: Conchoidal surfaces terminating in sharp edges and corners.
ANGULAR: Flat, plane surfaces, generally terminating in acute or right angles. Edges commonly thin to sharp.
SUBANGULAR: Flat plane surfaces terminating in well-rounded edges.
ROUNDED: Generally rounded surfaces, broadly rounded edges and corners.
GLOBULAR: All surfaces convex. Nearly equidimensional. Spheroidal.

The roundness of a grain has little to do with its over-all dimensions. A perfectly rounded grain can be elongated or flattened if rounding has progressed

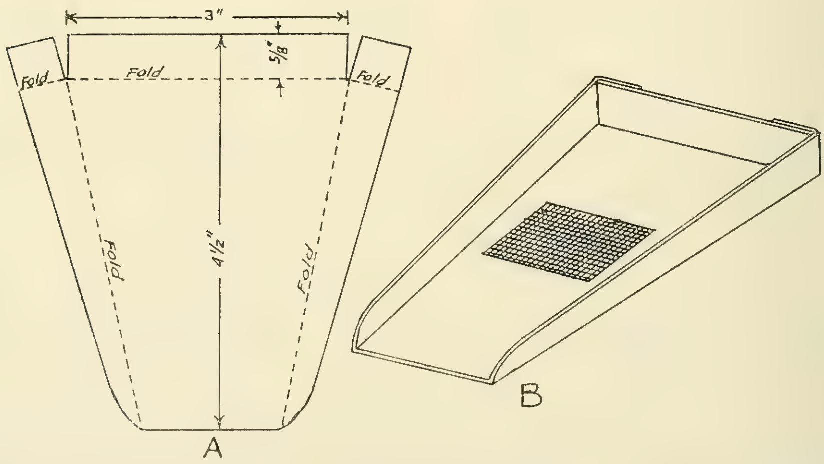

FIGURE 3-2. *A*—Plan for cutting sheet-metal scoop tray for viewing samples under the microscope. The material, preferably aluminum, can be cut with tinners' shears. *B*—Completed tray with 0.5 millimeter grid for measuring sand grains.

as far as the original dimensions of the grain will permit. Thus, a cylinder with hemispherical ends is perfectly rounded.

Sphericity, in contrast to roundness, is referred to the three dimensions of the grain. A cube has a high degree of sphericity, but a low degree of roundness. A sphere exhibits perfect roundness and perfect sphericity.

3. *Luster:* This term is used here in a rather loose sense to describe the condition of the surface of the sand grain. The luster or surface texture of sand grains sometimes reveals the history of the grain before and possibly after, deposition. Below are definitions of commonly used terms.

COATED: Precipitated or accretionary material on the surface of the grain. Iron oxide, calcium carbonate, sulphates, clays, pyrite, etc.
PITTED: Solution or impact pits, often of pin-point size.
FROSTED: Deeply etched, frosty, translucent, usually white.
SILKY: Lightly etched or scoured.
OILY: Greasy or oily sheen; common in hematite and magnetite grains.
VITREOUS: Glassy, shiny.

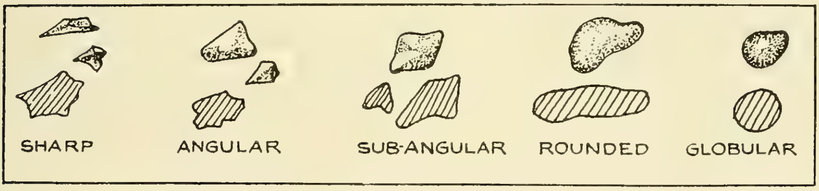

FIGURE 3-3. Illustrating the 5 classes of sand-grain shapes.

4. *Induration:* The induration of a sandstone is its resistance to physical breakdown or disaggregation. Induration does not necessarily refer to the hardness of the constituent grains, though they may have considerable influence on the degree of induration. Common adjectives describing induration are dense, hard (as in quartzites), medium hard, soft, spongy, friable.

5. *Cementation:* The character and composition of cementing material should be identified when possible. The cementing of a sandstone has a significant bearing on its performance as an oil reservoir. The character of the cementing material may reveal much of the rock's depositional history and post-depositional alteration. One should note the relationship of the cement to the constituent grains. Common cements are calcite, dolomite, sulphates, iron oxides, silica, pyrite, clays, silts, and siderite. Some sandstones are compacted into firm aggregates, yet have no discernible cement.

6. *Minor Constituents:* In addition to the minerals constituting the bulk of the rock, other minerals in very small amounts may also be present. Such minerals are often called *accessories.* Although they constitute a negligible portion of the aggregate, their importance is disproportionate to their bulk.

These minerals are often diagnostic of the environment of sedimentation, source areas of the sands, or the modes of transportation. Some of the minerals may be diagenetic, and thus indicate the postdepositional history of the sandstone. Some of the more common minor constituents of sandstones are biotite, muscovite, glauconite, pyrite, barite, siderite, cherts, coals, solid hydrocarbons, and a variety of hard nonmetallic minerals.

7. *Color:* The color of a sandstone may be caused by the colors of the constituent grains, color of the cement, or by the staining of the entire aggregate. Staining is most common in surface sections, but it may also be prevalent at or near unconformities in the subsurface. Quartz sands may acquire a surface film of coloration during a period of exposure as free sand before final deposition either as a marine or non-marine aggregate. Color is an important character of the rock and should always be noted.

8. *Structure:* The structure of a sandstone as used in the description of well cuttings refers to such characters as laminations, fractures and fracture patterns, banding, and nodular or concretionary characteristics.

9. *Sorting (Texture):* The degree of sorting is one of the most important features of a coarse clastic rock. In petroleum geology, the sorting of sands in a potential oil reservoir has particular significance, for it determines the effectiveness of porosity and permeability of the rock. A poorly sorted sand generally has low porosity and permeability. The texture of the rock is determined, not only by its coarseness, but also by the sorting and arrangement of the grains.

The relative porosity and permeability of a sandstone can be estimated by carefully placing a drop of water on a dry chip and observing under the microscope how rapidly the water is absorbed into the rock.

Fine Clastic Rocks

(Plotted in natural colors of the rocks)

The dividing line between sandstone and siltstone is somewhat arbitrary. Wentworth and others make the distinction on the basis of a grain size of 1/16 millimeter. Although this division is entirely satisfactory for some types of work, it is not so practical for low-power binocular determinations. Most measuring devices are graduated in decimals of a millimeter, and for this reason 0.1 millimeter is widely used as the upper limit of siltstone grain size. In the application of this scale some consideration should be given also to other characteristics of the rock. If the rock is poorly sorted and the maximum grain size is 0.1 millimeter, it should be classed as a siltstone, or perhaps a sandy siltstone. On the other hand, if the grains are well-sorted and the maximum size is 0.1 millimeter, the rock should be called a very fine sandstone, or perhaps a silty sandstone.

The fine clastics group consists of clays, shales, mudstones, silts, siltstones, and graywackes. Clays and shales and silts and siltstones are differentiated on the basis of the degree of induration or lithification. For practical reasons, all clastics whose grains are invisible under 12× magnification are classed as clays or shales. Siltstones, silts, and graywackes are the fine clastics whose individual grains are distinctly visible under 12× magnification. If the grains are well-rounded and within the limiting grain size, the rock is a siltstone. If the grains are sharp to angular, particularly with feldspars, and are imbedded in a very fine matrix, the rock should be called a graywacke. Some graywackes contain grains much coarser than 0.1 millimeter.

The term *graywacke* has been variously defined, and students of sedimentology are by no means in agreement on the limiting composition and physical characters of the group. Inasmuch as the sample examiner is generally limited by low magnification of the microscope and broken rock surfaces, instead of sectioned surfaces, exact identification of constituents is difficult, or in some instances, impossible. Therefore, it is advisable to define the rock according to the observable properties. In general, graywacke is a fine to medium-grained clastic rock composed chiefly of angular quartz, with or without feldspar, and rock fragments—all imbedded in a fine matrix of silt, clay, chlorite, and other basic minerals. The larger fragments may have the dimensions of grains in rocks of the coarse clastic group.

The principal characteristics of fine clastic rocks are given below:

1. *Color:* In the subsurface, colors of shales and siltstones are often very significant, either in the correlation of stratigraphic units or in the determination of environments of sediment. It has been amply demonstrated in rocks of different ages in widely separated regions that the colors of shales indicate relative positions in a sedimentary basin. The normal lateral sequence from the shore toward the basin deep is bright red to red and green, to green and gray, to light and dark gray, to dark gray and black. This does not imply that all black shales originated in basin deeps or that all red shales are near-shore deposits. It is, however, a normal arrangement.

Krynine's analysis of rock colors shows that gray in varying amounts is generally present, even in the bright reds and greens. This is a useful principle to keep in mind when matching the colors of shales with colored pencils. The colored pencils alone are too vivid; but when a hard-lead pencil is applied over the colored area, a close match of the natural rock color is attained.

2. *Composition:* The exact chemical or mineralogical composition of a fine clastic rock cannot be determined by the means available to the sample man. However, by simple tests it is possible to distinguish such constituents as the following: montmorillonite, illite, kaolinite (or unclassified clays), calcite and dolomite, oxides of iron, sulphides and sulphates, phosphates, and silica. Certain tests for these constituents are presented later.

3. *Minor Constituents:* As in the coarse clastic rocks, fine clastics often contain small amounts of materials which enable the subsurface geologist to deduce certain facts relating to the deposit. These minor constituents are about the same as those that occur in the coarse clastic rocks. Fossils are generally more abundant in the fine clastics; in many sections they are limited entirely to the shale portions. Whatever the minor constituents may be, they should be noted in the description. When graphic symbols are provided, they should also be shown in the graphic column.

4. *Luster:* The lusters of shales are earthy, resinous (resinous shales are usually dolomitic), waxy, soapy, oily, silky, velvety, and sooty (some very black shales, such as the Chattanooga, are sooty in appearance).

5. *Structure:* Common structures of shales and siltstones are massive or lumpy (called mudstones), platy, laminated, foliated, fissile, splintery, flaky, jointed, and fractured. In some areas fractured shales serve as oil-reservoir rocks; therefore it is important to record the presence of fractures.

6. *Induration:* The degrees of induration, or hardness, are disaggregated (as in dried mud in the samples), spongy (usually salty or bentonitic shales), compact, brittle (dolomitic or siliceous), slaty.

7. *Inclusions:* Shales and siltstones frequently contain fragments of reworked and redeposited shales, limestones, and other types of rocks. They may also contain masses of gypsum; anhydrite; chert; iron oxides; nodules; and pellets of barite, pyrite and mud, oolites and concretionary materials, and grains of solid hydrocarbons and coals. Such extraneous grains or masses are termed, collectively, inclusions.

Carbonate Rocks

(Plotted in sky blue)

Because of the great variability of carbonate rocks, they are the most difficult for the beginning microscopist to understand and describe. They range from extremely heterogeneous to extremely homogeneous. The microscopist is faced on the one hand with the problem of summarizing a vast array of detail, and on the other with searching for suffcient minutiae to permit subdivision of the section. The situation is further complicated by the lack of uniformity in the uses of descriptive terminology. The following discussion will attempt to present the subject in a manner that will enable the microscopist to standardize the methods of sample determination to the extent that consistent results may be expected. Many of the tests herein presented have been compared with established standards and are therefore known to be reliable. However, they are not entirely infallible, and a great deal depends on the ability of the sample examiner to carry out the tests with care and to recognize conditions that might interfere with the tests.

Many carbonate rocks are composed of carbonate grains and fragments that have been deposited in essentially the same manner as sandstones or conglomerates. They are actually clastic rocks. If well samples were classified on the basis of origin or mode of deposition, these limestones would have to be considered with the clastic group. In certain investigations it is indeed necessary to treat such limestones with the insoluble clastics, but to attempt to do so in the examination and graphic presentation of well samples would only contribute to the confusion that already exists. Therefore, all carbonates, regardless of origin, are here included in one class, and in no case are they considered in the clastic group as previously defined. The rigidity of this presentation is necessary if the basic colors of the strip log (yellow and blue) are to have a constant meaning.

On the basis of composition, which can be determined by the sample man, the carbonate group is subdivided into two main classes: limestones and dolomites. The term dolostone may be used in place of dolomite, but general acceptance of dolomite as a rock name, as well as a mineral name, makes the term dolostone unnecessary. To the oil geologist, dolomite signifies a rock. There is almost an infinite number of gradations between the nearly pure end members of the group and the proportions of limestone or calcite, and dolomite in any specimen may vary considerably in a few inches. Therefore, a quantitative analysis would be of doubtful value. Within reasonable limits of accuracy it is possible for the sample man and his limited means of determination to recognize consistently two stages of the gradations, which are called dolomitic limestone and calcareous, limy, or calcitic dolomite. These subdivisions are determined by characteristic reactions in cold, dilute hydrochloric acid.

Use 1 part C. P. hydrochloric acid to 7 parts water.
Test the rock only in cold acid.
Test in a depth of acid not less than ½ inch.
Use chips about ¼ inch diameter, ⅛ inch thick.
Observe reactions under the microscope, if the effervescence is slow.

If there are no complications, the reactions will be about as follows (fig. 3-4).

Limestone: Violent effervescence; frothy audible reaction; specimen bobs about and tends to float to the surface.

Dolomitic Limestone: Brisk, quiet effervescence; specimen skids about on the bottom of the container, rises slightly off bottom; continuous flow of CO_2 beads through the acid.

Calcitic Dolomite: Mild emission of CO_2 beads; specimen may rock up and down, but tends to remain in one place.

Dolomite: No effervescence; no immediate reaction; slow formation of CO_2 beads on the surface of the rock; reaction slowly accelerates until a thin stream of fine beads rises to the surface.

These reactions are somewhat modified by the presence of noncarbonate constituents or the physical characters of the specimen.

Finely disseminated anhydrite, clays, and other inert substances retard the acid reaction sufficiently to cause a limestone to react like dolomite or dolomitic limestone. However, there are at least two ways in which to distinguish them. The reaction of dolomite is very slow at first, but becomes more vigorous after a few minutes or seconds in the acid. Impure limestone will effervesce strongly at first, but the reaction progressively lessens. A pure dolomite is entirely soluble; an impure limestone leaves an insoluble residue when acid reaction has ceased.

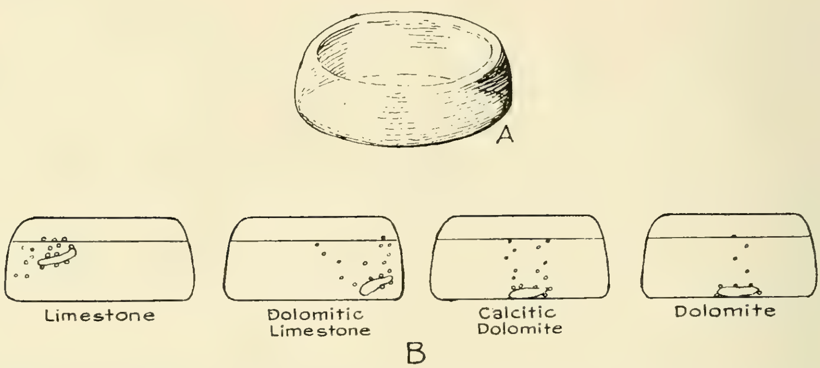

FIGURE 3-4. Acid tests of carbonate rocks. *A*—Glass furniture leg coaster used for acid. *B*—Characteristic reactions of limestone and dolomite.

Very porous and permeable dolomite may react like a limestone because of the greater surface area exposed to the action of the acid and the greater buoyancy due to pore spaces. Some allowance must be made for such rocks in appraising acid reactions. One should attempt to select less porous chips from the sample for testing.

Concentrated acid has higher viscosity and specific gravity than dilute acid. The high viscosity permits greater accumulation of the CO_2 beads in the acid above the specimen, and greater buoyancy is provided by the higher specific gravity (and viscosity). To safeguard against misinterpretation, one should use only acid diluted as specified earlier.

Carbonate reaction is much more vigorous in warm acid than in cold. *Always make limestone-dolomite determinations in cold acid.*

Finely divided dolomite reacts like a limestone. This fact should be kept in mind when one is examining finely ground cable-tool samples. Pulverized dolomite on the surfaces of the chips will give an initial reaction similar to limestone, but the reaction will slow down when the fine material has gone into solution. *Watch the reactions to ascertain that the CO_2 is coming from the solid chip.*

Acid reactions are unreliable when the test chips are wet with water before they are introduced into the acid. The film of water on the chip and water filling the pores prevents immediate contact of the acid with the rock.

Calcareous shales and sandstones sometimes react as violently as pure limestones. One should check the reacting chip from time to time for insoluble residues. Dolomitic shales and sandstones, likewise, may react like dolomite.

Weak, partially spent acid gives correspondingly weak reactions. One should keep near at hand a few small test chips of carbonate whose reactions in acid of the right strength are known. The acid should be checked periodically by means of these test chips. Fresh acid should be obtained frequently when one is working largely with carbonate rocks.

A number of stain tests for differentiating dolomites and calcitic limestones are applicable only to very light-colored rocks, and all are *more* effective on light colors. Stain tests are very good for determining the manner of distribution of dolomite and calcite grains or crystals in the rocks. The method given below is quite easy to use, since it does not require hot solutions. It is known as the Fairbanks method.

Mix 0.24 gram of haematoxylin and 1.6 grams of aluminum chloride in 22 cubic centimeters of water. Bring the solution to a boil, and then allow it to cool. Then add a small quantity of hydrogen peroxide, and filter. Keep the solution in a dark glass bottle.

To test a specimen in Fairbanks solution, immerse it for a few seconds and then rinse it immediately in clean water. Do not use a strong stream. The calcite will take on a deep purple color, while the dolomite will be unaffected. Beware of finely porous or sucrosic rocks, for some of the stain may lodge in the interstices and give the appeance of staining. When staining thin or polished sections, first etch them slightly in acetic or hydrochloric acid. Etch only sufficiently to produce a dull surface on the calcite. Wash immediately in water and dry thoroughly before applying the stain.

Grain Size: The grains of carbonate rocks vary greatly in size and general appearance in short lateral and vertical distances. It is necessary to describe the grains completely in order to determine the origin of the rock. The grains may be fragments of limestone, shells, microfossils, oolites, algal remains, crystals or precipitated grains, or any combination of these types. Grain sizes are measured by means of diaphram scales and grids, or grids placed in the scoop tray. The latter are not entirely satisfactory because of the difficulty of breaking down the carbonate rocks to individual grains.

The grain-size classification given in the following table is a modification and simplification of various classifications occasionally used in some institutions. Technical names for the different grain sizes have been avoided in favor of every-day adjectives which everyone will understand.

TABLE 3-II

Grain-Size Classification

	Millimeters
Coarse	over 2.00
Medium	2.00 to 0.25
Fine	0.25 to 0.05
Very Fine	0.05 to invisible
Below the range of 12× power are two classes:	
Sublithographic	dull luster, earthy, opaque
Lithographic	porcelaneous, semi-translucent

The relative proportions or distribution of grain sizes can be recorded as follows:

"0.01 to 0.15" indicates a gradation of grain sizes within the stated range.

"0.01, max. 0.15" indicates a preponderance of fine material with occasional large grains.

"0.05" means an even-grained rock with the stated average grain size.

Character of Grains: The origins of carbonate grains, as indicated before, are widely different, and a description of such a rock is not complete unless the character of the constituents is included. It is usually not sufficient to state "fragmental limestone" or "oolitic limestone." The fragments and oolites should be described. Oolites may be classed as spheroidal, spherical, elliptical, irregular, flattened, etc. Fragments are described in much the same way as sand grains: sharp, angular, subangular, rounded, and globular (or spheroidal). When discernible, the origin of the fragments should be given also; i.e., coral, shell, or limestone fragments.

Texture: The textures of many types of limestones will be indicated if grain shapes and sizes are stated as suggested above. However, certain textural terms are widely used in the descriptions of crystalline varieties and are well established in the vernacular of the oil geologist; and in view of this fact, they are given in Table 3-III. It has been observed that certain types of porosity are frequently associated with specific textures. While the textural and porosity types are not always associated, the frequency is sufficient to warrant attention.

Structure: Structural features of carbonate rocks include stylolites, fractures, microfractures, laminae, banding, crinkling, concretions, whorls, and brecciation. Many of the structural characters can only be inferred from the small chips.

Color: The "normal" colors of limestones and dolomites are gray, white, buff, and brown. Less frequently they are red, orange, various hues of green, purple, and black. These colors may occur in combination in a variety of patterns, such as mottling, banding, speckling, and grading. The manner of color-

TABLE 3-III
Texture Classification

Texture	*Typical Porosity*
Rhombic—perfectly formed rhombs of nearly equal size, medium to coarse (usually pure dolomite)	Vuggy, drusy crystals in vugs
Sucrosic—sugary, similar to rhombic, but finer, lacking the perfection of crystal form; friable (usually calcitic dolomite)	Interstitial, tubular to cavernous
Microsucrosic—very finely sugary, often quite friable (dolomitic limestone)	Tubular to cavernous
Grainy—not visibly crystalline but with definite grains, often chalky in part (limestone or dolomitic limestone)	Pin point to tubular or vermicular
Subcrystalline—glassy or resinous mass (usually pure dolomite)	Sparse pin point, tendency to fracture
Slabby—very coarsely crystalline, uneven grain size (rarely dolomitic)	Usually nonporous
Oolitic—spheroidal or smooth-surfaced grains with concentric internal structure	Intergranular or isolated pin point
Pseudo-Oolitic—rounded clastic grains simulating oolites	Interstitial to isolated pin point

ing should be stated in the sample descriptions, and, in cases of unusual coloring, shown on the strip log. Red and orange speckling and mottling often occur above and adjacent to large structural uplifts. Red, green, and orange are often associated with surface weathering, unconformities, and subsurface oxidation through the action of circulating waters.

Inclusions: The term "inclusion" is used herein with certain reservations. Masses of noncarbonate material commonly called "inclusions" are in many instances chemical replacements of the original rock. The distinction can usually be made when the rock is viewed in thin or polished section, but not in the rough chip. Anhydrite and gypsum commonly occur as small isolated masses in the carbonate rock. These masses may be either replacements or inclusions that are contemporaneous with the host rock. Cherts occur in a similar form, and likely have a similar origin. Unless these masses can be identified as replacements, it is better to describe them simply as inclusions—a non-specific term.

Evaporite Rocks

(Plotted in black-line symbols)

Although some carbonates are evaporitic in origin, it is impracticable to so treat them in well-sample work for the same reasons that clastic limestones are not considered with the clastic group. This group is restricted to anhydrite, gypsum, salt, and such other chlorides and sulphates as can be identified.

It is not always possible to distinguish between anhydrite and gypsum by observation. Mixtures of the two are very common, and alteration of anhydrite to gypsum may occur under favorable conditions in a matter of a few weeks. Ordinarily, the distinction can be made on the basis of the following characteristics:

Anhydrite is often amorphous-appearing though it does possess perfect cleavage. Its hardness is considerably greater than that of gypsum; it cannot be scratched with the fingernail. It tends to be translucent with a pearly luster. Gypsum occurs as a fibrous-to-lacy mass of selenite crystals, as a glassy solid mass with a subvitreous luster, or as a snowy earthy-to-massive rock (alabaster). Any form of gypsum can be scratched easily with the fingernail. Anhydrite is brittle; gypsum is usually spongy. One should note the manner in which the chip breaks when crushed on the microscope stage.

Rock salt (halite) can usually be identified by its taste, solubility in water, and perfect cubic cleavage. When it occurs in finely disseminated crystals, it might be confused with barite, which has a prismatic cleavage. Barite is insoluble in water and almost insoluble in cold or hot hydrochloric acid.

There are certain other evaporitic salts of sodium and potassium, but their importance as rock makers is comparatively minor. When such minerals are suspected, and if it is important to identify them, quantitative chemical analyses should be employed.

As mentioned in an earlier paragraph, anhydrite sometimes alters readily to gypsum. This process sometimes occurs when anhydrite is exposed to certain types of fluid in the course of drilling a well. The alteration to gypsum, which is accompanied by an increase in volume, results in swelling into the hole. When this process is going on, abundant anhydrite cavings are liable to appear in the samples some time after the formation has been drilled. When anhydrite or gypsum recurs in the samples associated with lithologies which do not suggest evaporitic conditions, the drilling records should be checked to determine if trips were made at the depths where the evaporites appear. These cavings generally are caused by the shutdown of the mud pumps.

SOME PRECAUTIONS IN SAMPLE EXAMINATION

As has been suggested in the foregoing pages, there are numerous situations wherein the well-sample examiner might be led into erroneous interpretations of the samples. For the benefit of those to whom the process of examining well samples is a new undertaking, the more common pitfalls are listed below. The purpose of this check list is to put the novice on guard against errors that are made all too often, occasionally even by those having considerable experience.

1. Cement is used in wells to set casing, regain lost circulation in highly porous and permeable zones, and in some instances to hold pieces of drilling equipment that have been lost in the hole so that fishing or milling tools can be used more effectively. Cement appears in the samples as a chalky limestone, and it reacts in acid as a limestone. There are few sample men who have not at one time logged cement as chalky limestone. One should check the drilling records for drilling operations mentioned above. Cement is almost invariably peppered with minute black specks. It would be a rare limestone that would have the even distribution of specks so characteristic of cement.

2. Commercial drilling muds are made from clays, iron oxides, barite, bentonite, and other mineral substances. When samples are improperly washed, the dried mud may be logged as formational materials. Occasionally clays and shales near the well site are ground and used as drilling mud. They may be poorly prepared so that small chips will appear even in the washed sample. Hematite weighting material stains samples red. One should check on the kind of drilling fluid used in the well.

3. A large variety of substances are used for the purpose of reducing the loss of drilling fluid into porous formations. These materials may not be eliminated in the washing of the samples and might be mistaken for mineral constituents of the rock. Cellophane flakes, for example, might be mistaken for selenite or muscovite. Organic substances, such as cellophane, ignite in a match flame.

4. Sometimes lubricating oil is inadvertently splashed on cuttings or cores at the drilling rig. It is difficult to distinguish light lubricating oil from crude in small amounts adhering to drill cuttings. Examine freshly broken chips. Extraneous oil will likely remain on or very near the surface; naturally occurring oil should be found in the interior of some of the chips.

5. Stylolitic surfaces in limestones and dolomites appear as black oily films. Crude petroleum occurring in fractures and along bedding planes is quite similar. A match flame will quickly distinguish one from the other.

6. Up-hole cavings and recirculated cuttings are the microscopist's biggest problem. The danger of relogging caved materials has been discussed. However, there is some danger in the sample examiner becoming too sensitive to the problem. He may develop the tendency to call all recurring lithologies cavings from the depth where the lithology was first described. When in doubt, compare the chips directly with the ones logged earlier. There may be some slight differences not apparent from the descriptions, but sufficient to establish the identification.

7. Samples should be run under uniform conditions of lighting and magnification.

8. Only dilute hydrochloric acid (1 to 7) should be used, but the strength of the acid should be checked frequently.

9. It is not unusual for gaps to occur in the sequence of well samples. These gaps may be as small as three feet or as large as several hundred feet. The sample man quickly acquires the habit of describing and plotting samples at regular intervals, as, for example, 10 feet, without actually checking the depths on each envelope. A sample gap may not be noticed for some time, with the result that lithologies occurring at one depth are plotted on the strip at another position higher up the hole. When logs are plotted in ink as they are run, such a mistake is a serious matter, and may be one which cannot be corrected entirely. One should always compare the depth of each sample with the depth on the strip log before plotting the description.

10. When a change in lithology is encountered in the samples, the material should be examined closely; then an attempt should be made to trace the lithology back up the hole in the samples previously examined. Where the top of the formation is first drilled there may be very little of the representative rock in the sample, a fact which could have been overlooked in the first examination. The tops of main stratigraphic units should always be established in this way. It is helpful to have briefly looked at a few samples down the hole before studying the one to be plotted next. Some microscopists prefer to work with several scoop trays simultaneously, so that principal changes in lithology will be anticipated. This is a good practice.

11. Good use should be made of electric-logs, drilling-time logs, and the like. One is prone to become so interested in the problems of the actual sample examination that these sources of information are neglected. However, do not depend on such logs to supply information that should be obtained from the well cuttings. A lithologic log should be constructed on data obtained from the cuttings wherever possible, not on an interpretation of indirect methods of logging.

MISCELLANEOUS TESTING METHODS

Considerable judgment and ingenuity must be exercised in performing the tests used in connection with sample examination. Techniques employed in mineralogy are usually not applicable to this type of work because of the small sizes of the particles. Therefore, many of the tests are not conclusive. The following tests have been adapted to well-sample determination:

Hardness: Unless abrasion or scratch tests for hardness are made carefully on small grains, the crushing effect is likely to be mistaken for scratching or abrasion. It is impractical to employ the standard mineral scale of hardness. A steel needle, a brass wire, and a small knife blade may be used as follows:

Hold the chip firmly on the microscope stage with the forceps. While viewing the operation through the microscope, lightly rub the point of the steel needle back and forth across the grain being tested. Apply very light pressure.

If the mineral takes flakes of steel off the needle and shows no abrasion, the hardness is approximately 6, or greater. Quartz, feldspar, and many other silicates fall in this category of hardness. If the hardness is less than 6, the mineral will show abrasion, and no steel will be cut from the needle. In this case, next try the brass wire, whose hardness is from 3 to 4. Proceed as above, using very light pressure, until either the wire or the mineral shows abrasion. If the grain is scratched by the brass wire, try the fingernail, whose hardness is about 2½. Selenite (gypsum) is easily scratched by the fingernail; anhydrite is not. By working carefully between these gauges, one can make accurate estimates of the hardnesses of minerals from 1 to 6. After considerable practice and experience, one can estimate the hardness with reasonable accuracy by scratching with a steel needle.

The hardness of small grains imbedded in very fine matrix is judged by rubbing the flat surface of a knife blade over the area. If the grains are harder than the metal, they will gouge tiny flakes of metal from the tool. The side of the needle or brass wire can be used in the same manner.

Solubility: The acid reactions of limestones and dolomites have been described in detail on page 31. It is sometimes desirable to observe the general characters of insoluble constituents of carbonates, although time and lack of facilities will not permit a standard insoluble-residue analysis. A satisfactory substitute method consists in placing a small chip in the acid dish and, when the reaction has ceased, re-examining the insoluble portion under the microscope. In order to save time, regular examination of samples down the hole is continued while the acid reaction is in progress. When such tests are frequent, several acid containers can be used to advantage. The insoluble residue may be examined under the microscope while still immersed in the acid, provided the effervescence has ceased and only low-power lenses are used. When the insoluble portion does not break down, the aggregate may be carefully lifted out of the acid with the forceps, lightly rinsed in water, and laid on blotting paper for examination.

The water solubility of certain salts has been discussed. Barite in finely divided particles may appear much like some varieties of anhydrite. The material should be boiled in hydrochloric acid. Anhydrite is slowly soluble, barite is not. Then the solution may be tested with a few drops of barium chloride solution. If a sulphate is in solution, a heavy white precipitate is formed.

Ignition: Solid hydrocarbons and carbonaceous materials such as gilsonite and coal rarely occur as redeposited grains in sandstones and shales. To test, one should hold a chip in the forceps in the flame of a match. After the chip is heated for a moment, it is removed from the flame and the odor of the fumes noted. Liquid or solid hydrocarbons and coal have quiet different odors on ignition. Coals leave a powdery ash; hydrocarbons leave a black film or a spongy mass.

Tests for Oil: The simplest test for suspected oil stains in a rock is by fluorescence under ultraviolet light, provided, of course, that a fluoroscope is available. If fluorescence is not obtained with a dry chip, it should be immersed in ether or carbon tetrachloride for a few minutes and re-examined in the ultraviolet light. Some minerals have characteristic fluorescence under ultraviolet light. One must be sure that the fluorescence observed is actually from the oil stains and not from certain minerals. Chips having no visible stains should be compared with those that are stained.

A delicate test for soluble hydrocarbons is as follows (C.P. acetone and distilled water are the reagents):

Select a few stained chips and mash them to about match-head size. Blow the dust away so that it will not interfere with the test. Place the broken chips in a small test tube half filled with acetone, and shake the tube for a few minutes. Filter into a clean tube. Add a few drops of distilled water and shake again until thoroughly mixed. If hydrocarbons are present, even in very small quantity, the solution will become milky, and the density of the cloudiness is an indication of the amount of hydrocarbon present.

In cases of very faint cloudiness, compare the test solution with a similar tube containing only acetone. Hold the two tubes side by side against a dark background.

Hydrocarbons are more soluble in one solvent than another, depending on the nature of the hydrocarbon. When ether or carbon tetrachloride is used, the following procedure is recommended:

In addition to the solvents, only chemical watch glasses are needed. Make certain that the watch glasses are completely free of oil or grease by cleaning them with the solvent and paper cleansing tissue.

Place a few stained chips on the watch glass and add sufficient solvent to cover the chips. Stir the chips with a glass rod or needle to agitate the solvent. Do not use a match stick for this purpose; it may contain some oil. Allow the solvent to evaporate completely. Now examine the watch glass under the microscope for residual oil rings on the glass. Weak stains leave only a ring of oil film; strong stains leave rings composed of minute globules of oil.

It is difficult to detect light-colored oil stains in similarly colored dolomites, and solvents may not reaily remove the oil from impermeable rocks of this type. If the solvent tests fail to give a satisfactory answer to the problem, proceed as follows:

Break or grind the rock into fine particles and dissolve in pure, dilute hydrochloric acid in a clean dish. When the material is completely in solution and the reaction has ceased, examine the acid under the microscope. If oil is present in appreciable quantity, a residue film will accumulate on the surface of the acid.

Special Techniques: Small pieces of the plastic polaroid can be used with the ordinary low-power binocular microscope to serve the same purpose as nicol prisms in the petrographic microscope. Place one piece beneath the stage of the microscope where the light to the specimen will pass through it. The second piece is inserted between the thin section and the objective lenses. A small wire holder can be attached to the microscope to which the upper piece of polaroid is fastened. When used only occasionally, the upper polaroid sheet may be held in the right position in the hand. The specimens must be in the form of thin sections.

A small magnet may be used to remove magnetic grains from disaggregated sandstones. Some black hematite is identical to magnetite in appearance, but the two are easily separated with the magnet. After the magnetite has been removed, the sample can be heated, then cooled, after which the hematite becomes temporarily magnetic and can be removed with the magnet.

In the study of carbonate rocks it is sometimes desirable to obtain a polished section, even though the majority of determinations do not require this type of examination. Lapping wheels and other necessary equipment are usually not available. A polished section can be made very quickly from a sample chip with a few pieces of inexpensive equipment consisting of the following:

Geared emery grinding wheel, hand-operated, home-shop type, that can be clamped on the edge of a table.

Abrasive 4-inch wheels of about 80 to 150 grit.
Plate glass 1/4 inch thick and 5 inches square.
A few sheets of wet or dry emery paper of 150 to 400 grade.
Hard sealing wax.
Dowel pin 5/8 inch diameter and a few inches in length.
Light machine oil.
Model airplane "clear dope."

A small amount of heated sealing wax is placed on the end of the dowel pin. The wax is reheated and the chip is pressed down firmly into the soft wax on the end of the stick. The chip is now ground to a plane on the side of the emery wheel and polished on the emery paper to the necessary degree of fineness. The emery paper is held on the glass plate when the specimen is ground. Either oil or water may be used in the final grinding. A thin coat of "clear dope" on the plane surface will bring out detail so that a high degree of polishing is not necessary. The wax is reheated to remove the chip.

A rough plane surface can be made quickly with a fingernail file or a small, fine machinist's file. The chip is not difficult to hold if placed on a flat pencil eraser. File marks are removed with fine emery paper.

Several stain tests been developed to differentiate the main groups of clay minerals: illite, montmorillonite, and kaolinite. Most of the tests are very exacting and require more equipment than is normally available to the well-sample examiner. All clay-stain tests demand a great deal of care; none is infallible. The tests are often confused by mixtures of more than one mineralogical type, and in some cases are difficult to interpret because of the absorptive properties of clays.

The following test is comparatively simple, is fairly reliable, and does not require special apparatus. The reagent is benzidine hydrochloride, which has a pink color. When this stain is applied to kaolinite, there is no color change. When it is applied to bentonite or illite clays, the color changes to blue. A number of impurities, including gypsum, interfere with the test.

Another test, which requires acid treatment of the specimen, employs a solution of 25 cubic centimeters of nitrobenzene and 0.1 gram of crystal violet. The solution is vivid purple.

First the clay is boiled in strong hydrochloric acid for at least 30 minutes; then it is washed thoroughly in distilled water, and in clean water two or three times. The specimen is dried at about 105C, and the solution is applied. Kaolinite simply absorbs the purple stain; illite turns dark green; and montmorillonite first stains green, then changes to greenish-yellow or orange.

RECORDING THE DATA

Descriptions of Well Samples

The descriptions of well samples should adhere to a definite style or pattern. Written descriptions are much easier to plot if the name of the rock is given first; then the various characters should be described in a consistent order. When this plan is followed, it is more convenient to compare like characters of the different lithologic units.

Example:

Ss—0.1 mm, angular, compact, muscovite, buff.
Ss—0.5 to 0.9 mm, round, friable, glauconitic, red.
Ls—0.5 mm, oolitic, argillaceous, tight, dark gray.
Dolo—0.2 mm, rhombic, sandy (0.1 mm), brown.
Sh—red-brown, fissile, calcareous, micaceous.
Sh—dark gray, lumpy, silty, biotite, pyrite.

Typewritten logs made from the written descriptions of the microscopist have the advantage of being easily reproduced if a number of copies are needed.

Plotted Interpretive Logs

There is a considerable difference of opinion on whether the strip log should be plotted concurrently with the examination of samples or whether notes should be taken on the examination and the log plotted later. Each method has certain advantages over the other. As mentioned earlier, the notes can be typed when a number of copies are needed, or a strip may be plotted from them.

From the microscopist's viewpoint, it is much better to plot the log directly from the observation of samples. Colors do not require minute description, because they are shown on the log by direct matching with the rocks. Small differences in similar lithologies will be shown on the log, but they may be neglected in a plot from a word description. The greatest advantage is that the microscopist has always before him a graphic record of the rocks that have been logged up the hole. This is of the utmost importance when suspected cavings appear in the samples, for a glance up the log will indicate the depth from which the cavings may have come.

The written descriptions on strip logs follow the same general pattern as the example given above. Inasmuch as there is very limited space on the 3-inch strip, it is necessary to use abbreviations wherever possible. A list of abbreviations is presented at the end of this chapter. The strip may be plotted in standard black-line symbols or in color. The black-and-white log has only one advantage: that of duplication by photo-reproduction methods. Colored strips are more legible, are more pictorial, and are easier to draw. They are used universally in the oil industry, although the meanings of colors differ among oil companies.

While acknowledging the advantages in various color symbolizations in use, the system presented here is simple in principle, yet so adaptable that all conceivable mixtures of lithologies can be shown. Briefly, it is as follows: All carbonates are shown in sky blue; extremely dense (lithographic) limestones or dolomites are shown in a darker shade of the same color. All coarse clastics are represented by the basic color canary yellow. All evaporites (noncarbonate) are shown by black-line patterns. Shales are shown in colors that match the actual colors of the rocks. Siltstones and graywackes are diagonal bands of natural color alternating with bands of canary yellow. In other words the lithologies are midway between shales and sandstones, and the log representation, likewise, is a combination of the respective colors.

Minor constituents in the main rock mass are shown in the representative colors of the lithologies in 45-degree bands drawn down from right to left. Thus a sandy and calcareous shale would be shown by a yellow band and a blue band across the shale color.

The accessory constituents, such as mica and pyrite, in many cases are represented by symbols suggestive of the minerals. These symbols are inked in black.

Colors of limestones are shown on the log only if unusual, such as red, pink, or orange, by diagonal bands across the blue, extending downward from left to right. The bands indicating color are not bounded by inked lines; those showing minor constituents, crossing the color bands, are inked. There is no confusion between a red limestone and a red *shaly* limestone. A speckled limestone is indicated by color stippling; mottled limestones, by mottled colors.

The dolomite symbol is a right-to-left diagonal dark-blue ruling. The background color is light blue, or the color of the rock. The same method is used for evaporites, in which case the black-line symbol is drawn on the appropriately colored background.

Application of Color

During the past 15 years the writer has experimented with a large number of colored pencils, crayons, and various other mediums of color in their application to geologic maps and well logs. In addition to the coloring phase, various fixing or preserving materials have been tested. The following discussion is based on this work. It is not held that other materials and methods are not equally satisfactory, but that these methods are known to be reliable. Therefor, the use of specific trade names or brands does not necessarily signify a quality superior to others; but, rather, that consistent results may be expected when they are used. It is highly important to use only certain fixing mediums with specific colored pencils; otherwise, the solvents in the lacquer may cause the colors to run or mix, and in so doing ruin the log.

There are two general types of colored pencils: the wax base or "waterproof" and the indelible or water soluble. Use only the indelible type, regardless of the brand. The Mongol indelible colored pencil maintains a high degree of uniformity in color hue and tone and in composition. It blends easily with a charcoal blender and is not disturbed by lacquer.

Colors on the logs are buffed to an even tone with blenders, or charcoal stumps, which are composed of paper pulp. When colors are combined to produce various intermediate hues, each application of the pencil is buffed before the next is applied. The first color applied to the strip retains the strongest hue in the mixture. For example, blue, then red results in bluish-purple; red, then blue results in reddish-purple.

The microscopist should experiment with mixtures of the different colors so that he can readily match the colors of the rocks. When some knowledge of the mixing of colors has been acquired, the work of plotting logs is greatly diminished. The nine pencils listed earlier, together with drawing pencils of two or three grades of hardness, are quite sufficient to make all the colors needed for plotting a well strip.

Plotting Templet

The cellulose-acetate plotting templet is shown in Figure 3-1. When this material is scratched deeply, or cut lightly, and then bent, it will break along the scratch. The templet is made by carefully cutting lines along the outlines of the slots and then bending sharply over the thumb nail. The edges of slots are sanded lightly.

The templet, with log inserted, as in Figure 3-1, is placed on the table in the most convenient position and then fastened to the table by Scotch drafting tape. The templet will now hold the log firmly during the course of plotting.

The diagonal slot at the top is for outlining in pencil or ink the areas to be colored for minor constituents. Coloring is also done through the slot. The second slot is used for filling in the rectangular graph for grain sizes.

The rectangular window is used for coloring thick, homogeneous lithologic units such as gray shales. Although the inked symbols for accessory minerals are usually drawn freehand, cutouts of the right size and shape can be made in the templet in order to achieve more uniformity in the symbols.

The minor-constituents slot is cut diagonally across 40 feet on the strip log. This approximately 45-degree angle has the advantage of exact duplication without a protractor.

Grain-Size Graph

A graph indicating the average grain size of clastic and carbonate rocks according to the classification coarse, medium, fine or very fine may be made without sacrificing description space on the log. Along the right side of the color column four light pencil lines are drawn parallel to the column and spaced 1/30 inch apart. The line nearest the column represents fine grains, the farthest out, coarse. When the samples are run, the graph is filled in with medium-gray pencil. Inked descriptions start at the edge of the column, disregarding the solid shadow graph, which will be discernible in spite of the lettering. The pencil guide lines are drawn with a steel straight edge the full length of the strip before the work is begun. At intervals where the graph is not used, the guide lines are erased. The templet may be cut as shown in order to draw the graph without guide lines. A grain-size graph is shown in Figure 3-5A.

Lettering of Logs

The order of descriptive terms on a log has been mentioned. The lettering should be in black waterproof ink. Various pens are satisfactory, such as the crow quill or Hunt No. 104. The latter is somewhat better because the point is more rigid, though equally fine. The log is somewhat more legible and distinctive if the rock name or its abbreviation is in vertical letters and the description in slant letters. Thus the descriptions of two or more rocks on a single line are more distinct.

The ink used in fine pens should be thinned with distilled water to which a few drops of ammonia have been added. A moist sponge in a cup is convenient for a pen wiper, and there is no danger of damaging the point as with a cloth wiper.

Porosity

The relative porosity of the rocks may be shown on the extreme right edge of the strip in different ways. The character may be indicated by dots, circles, and irregular figures, the relative degree of the porosity being suggested by the distance the pattern is carried to the left from the edge. A pencil shadow graph based on relative porosity or estimated percent of pore space can be shown on the right margin of the log in much the same manner as grain sizes are shown. In this case, the increase is shown from right to left (fig. 3-5A).

Cored Intervals

It is important to show the intervals cored in the well. Chip samples obtained during coring are inferior to regular cuttings. Chip samples taken from the cores are usually superior to cuttings. In the first case the log is likely to be less reliable through the cored interval than elsewhere. The reverse is true where core chips are used for the lithologic determinations.

Cored intervals are shown by a black line on the left side, and adjacent to the color column (fig. 3-5A).

Casing Points

After casing has been run in the well, there will be no caving from the wall above the bottom of the casing; therefore, the samples should be taken immediately after the casing is set. For this reason, the casing points should be indicated on the log, as shown in Figure 3-5B. The diameter of the casing is indicated at the casing point.

Title Information

The heading of the strip log (or typed log) should contain all information pertinent to the operation of the well.

Following is an outline for the completion of the title head:

- Location: State, county, section, township, range, and section subdivision
- Names of operator and landowner
- Name of structure or area
- Elevation above sea level
- Total depth of well
- Kind of equipment: rotary, cable tools
- Dates of starting and completion
- Daily rate of production (oil and gas)
- Stratigraphic unit from which production is obtained
- Casing points (if not plotted)
- Name of microscopist and date of sample examination

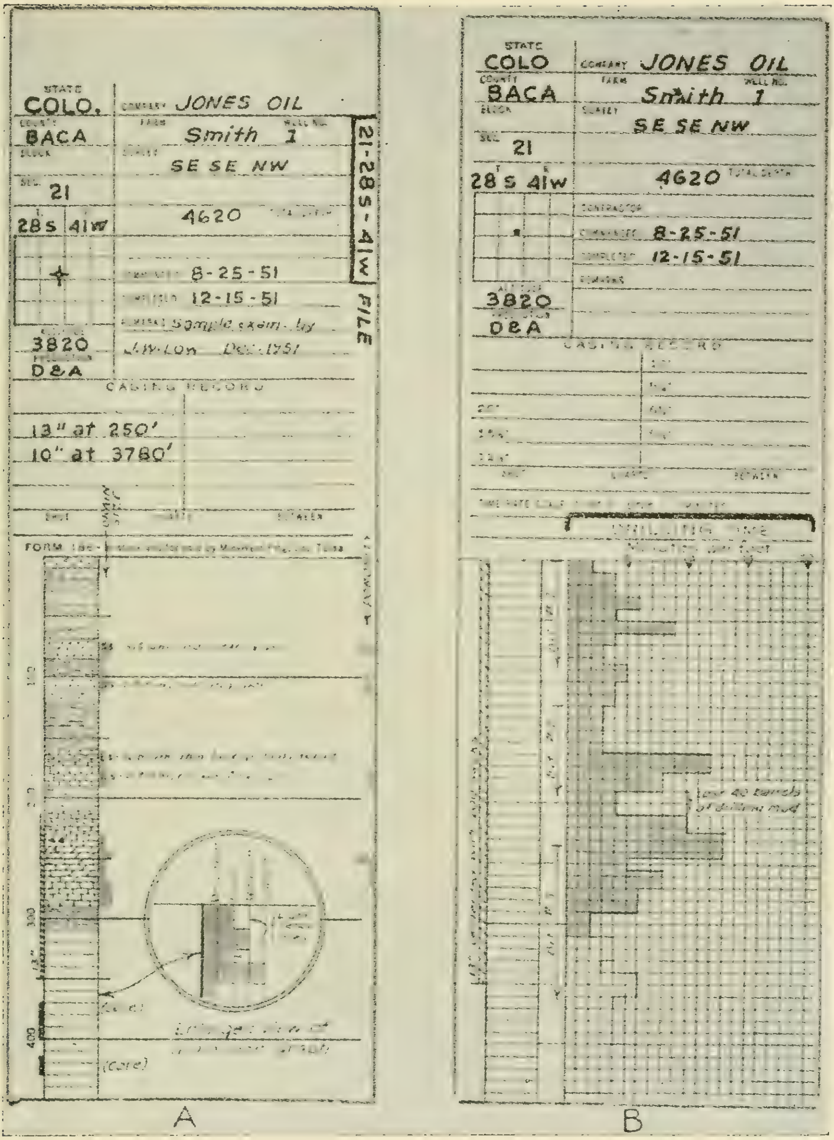

FIGURE 3-5. *A*—Lithologic log showing heading, grain-size graph, percentage porosity graph (on right margin), core and casing symbols on left side of lithology column. *B*—Drilling-time log plotted in minutes of time per foot of penetration. Also shown are bit record, casing points, and zones of lost circulation.

Core Descriptions

It is usually desirable to describe cores in more detail than space on the log permits. For this reason it is advisable to make a special plot on a larger scale at the bottom of the strip. This large-scale plot should bear a descriptive heading, and depth designations at the edge of the log must be changed to correspond to actual depths.

When the procedure given above is followed, the detailed core descriptions should be plotted first on the large scale. Then this description should be summarized to the extent that it can be plotted at regular scale (1 inch = 100 feet) in the proper position on the strip. The small-scale plot is necessary when the log is used for correlation with other logs. An example of this presentation of core descriptions is shown in Figure 3-6.

Engineering Data

Unless engineeering data have a specific lithologic connotation, they should not be plotted on the face of the lithologic log. Lithologic and stratigraphic descriptions and designations require all the space on the log, and extraneous data are introduced only at the sacrifice of space needed for the more pertinent information. An attempt to show both geologic and engineering information is bound to result in an inadequate presentation of both.

Some microscopists plot the results of engineering operations at the appropriate depths on the back side of the strip. While this method results in a presentation rather awkward to use, it does have the advantage of placing such information as drill-stem tests, lost circulation, and cementing jobs, where it can be appraised with direct reference to the lithologic log.

Preservation of the Colored Strip

The time required to examine the samples and complete a log of a well will range from a few days to as long as two weeks. The log is often the sole record of this work, and a simple calculation will demonstrate that its worth may be several hundred dollars. Obviously, the small amount of time required to protect it from deterioration with repeated use is insignificant compared to the time that has gone into its construction.

The inked white portion of the strip will withstand much use without serious deterioration. The color column, on the contrary, is damaged by handling and exposure to sunlight or moisture. The dry indelible colors tend to rub off or smear, and even a small amount of water changes the pencil colors to brilliant dyes, thus ruining the meticulous color work of the microscopist.

The color column may be preserved as follows:

The materials needed are (1) a good-quality artist's flat-bristle brush, ½ inch wide; (2) synthetic transparent lacquer, which can be obtained from craft

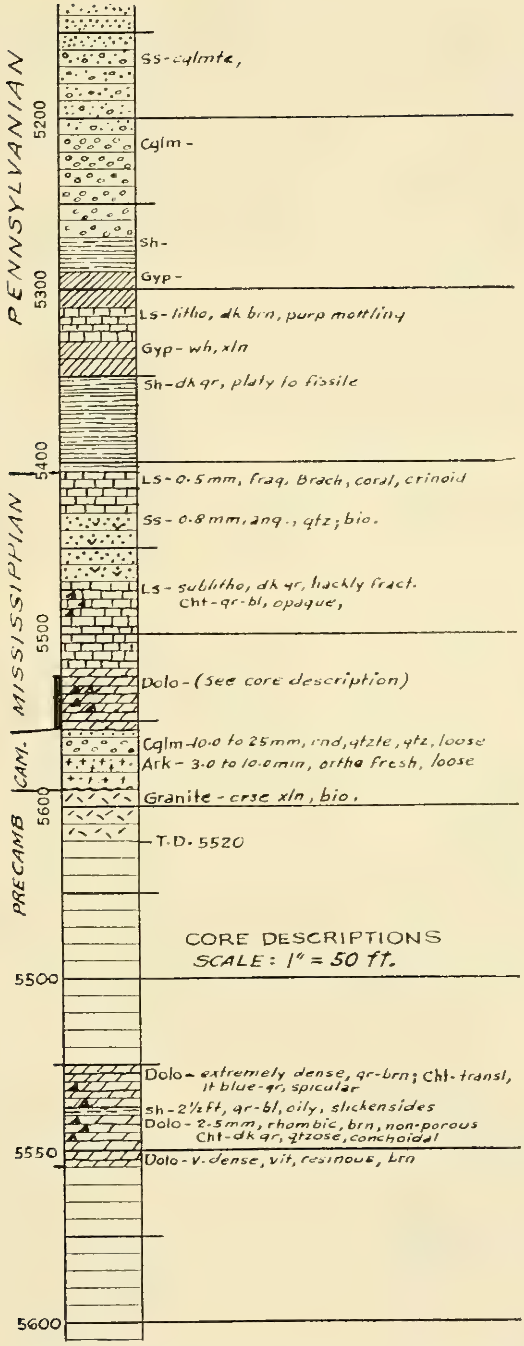

FIGURE 3-6. Showing a method of plotting core descriptions on an enlarged scale. Note repeated depth numbers on log.

shops or five-and-ten stores as clear model-airplane dope; and (3) lacquer or clear dope thinner, which is used to clean the brush.

The log should be laid flat on a table and the lacquer applied to the color column in a thin, even coat. After allowing a few minutes for drying, one should apply the second coat, which fixes the colors and renders them waterproof.

A plastic spray called Krylon, in an inexpensive pressured container, is also satisfactory. The entire log may be sprayed two or three coats and made waterproof. If only the color column is to be treated, the remainder of the strip must be masked from the spray.

One should not use varnish, which turns amber with age, or white shellac, in which the alcohol solvent will also affect the pencil colors.

Logs sometimes must be shortened in order to fit into file cabinets, but folding ruins the log. The log should be cut straight across and then rejoined with Dennison's gummed cloth library tape, 1½ to 2 inches wide. This tape serves as a hinge, and, if firmly burnished down, will last almost indefinitely. The top edge of the strip may be bound with tape and punched for hanging on pegs.

Percentage Strip Logs

In some parts of the country, percentage logs are more widely used than the interpretive logs described in the preceding pages. Two practices are followed in the construction of percentage logs:

(1) The unqualified percentage log shows the percentage of each lithology in the entire sample, without prior separation of the material thought to be caved from up the hole.

(2) The qualified percentage log shows the percentages of lithologies interpreted as freshly cut in the sample interval. The interpreted cavings do not enter into the calculations of percentage. This is the type of log most commonly used, and it is certainly the better of the two.

The lithologies are plotted in the color symbols used for interpretive logs. The strip is ruled vertically in intervals of 5 or 10 percent, and the percentages of the lithologies are plotted accordingly (fig. 3-7).

Although percentage logs are sometimes preferred, they have certain disadvantages. The relationships of stratigraphic units within a sample interval are shown horizontally, although they actually occur in vertical sequence. Stratigraphic interpretation of the samples is therefore passed on to the user of the log, who may never have seen the rocks. The sample examination is reduced largely to a mechanical process, which does not permit the sample man to reconstruct the stratigraphic column as it actually occurs.

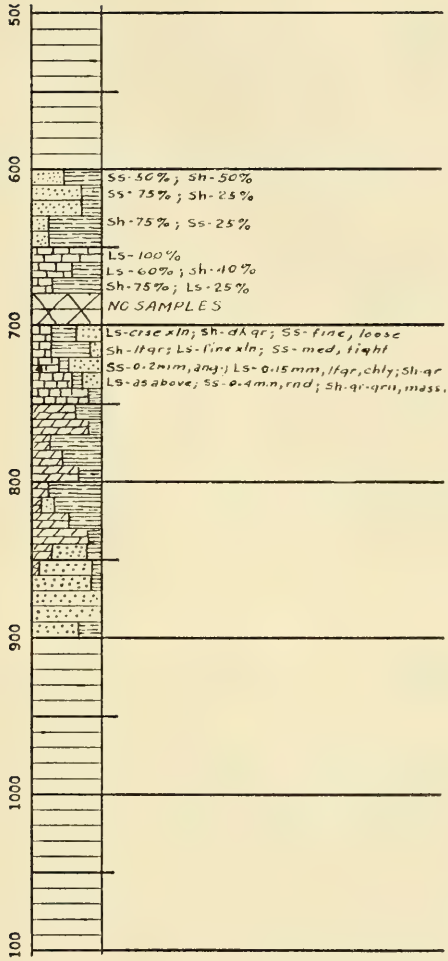

FIGURE 3-7. Lithologic percentage log.

REPRODUCTION OF STRIP LOGS

If it is anticipated that a number of copies of a strip log will be needed, the original log can be made in some form that is easily reproducible. Commercial log companies, which make a few to several hundred copies of the lithologic logs, first make an original on transparent material that will produce good copies in an Ozalid or similar machine.

At least one company makes a color reproduction by photographic methods, but the process is rather expensive.

When logs are plotted from the sample examiner's notes, the plot can be made on translucent material, such as vellum. All lettering and symbols are inked, including the inked parts of color symbols within the color column, but no color is applied to this original. Prints on heavy-grade paper are run off the translucent log. The prints are then hand colored.

A similar method consists in lettering and inking a standard well-log strip as described in the preceding paragraph. A film negative is made from the strip, and duplicate positives are made from the film negative by a continuous photostat process. The column is then colored with pencils.

All except the color column of a completed and colored strip can be reproduced in the following way:

Although the column will have to be hand colored on the reproduction, copying of the descriptions is avoided. The color column is cut from a blank log strip. This narrow strip is placed with the proper alignment of depth lines on the colored strip and taped in this position with transparent photo tape. With this as copy, a photographic film negative is made. Prints from the negative are identical to the original, except that the column is a ruled blank. Colors and symbols are copied from the original.

SUPPLEMENTAL USES OF OTHER TYPES OF LOGS

The lack of exactness in picking stratigraphic boundaries and occasionally in the interpretation of caved and freshly cut materials can be minimized through judicious use of drilling-time, electric, and radioactivity logs. These aids to detailed sample logging should be employed with restraint, because it is not difficult for the sample man to get into the habit of interpreting lithologies from the mechanical logs instead of the samples. In sections of sandstones and shales this mistake can actually be made with considerable assurance, but in sections of highly diversified lithologies, particularly in carbonate sections, the examiner must rely principally on his interpretation of the cuttings.

Drilling-Time Logs

It is common practice on drilling rigs to maintain a complete record of the progress of the hole. This record may be in the form of feet per hour or minutes per foot. In either case, the rate of penetration can be plotted on a strip log and thus serve as a valuable tool for the sample examiner. Usually the breaks in drilling time correspond to some visible change in lithology (fig. 3-5). Very porous zones in dolomites and limestones normally are drilled at a faster rate than the denser portions. Changes from shale to sandstone, gypsum to shale, and so forth, are frequently reflected in the rate of drilling. However, the manner of change—slow-to-fast or fast-to-slow—is not always the same in similar sequences of rocks. The following example illustrates these relationships:

Rock	*Drilling time* *Minutes per foot*
Shale	4
Sandstone	15
Shale	6
Sandstone	15
Shale	12
Sandstone	8

It can be seen that the relative rates of drilling of shale and sandstone are reversed in the top two and bottom two units. Nevertheless, the changes are obvious, and these breaks aid the sample man in fixing boundaries on lithologic units.

Factors other than the character of the rock also affect the rate of drilling. Some of these factors are type of drilling fluid, speed of rotation, rate of circulation of fluid, weight on the bit, and sharpness and kind of bit. A bit designed for drilling shale would be poor for hard sandstones. When a new bit is run into the hole, the rate of drilling is generally higher. However, the *relative* rates in various lithic units are not greatly affected.

Several oil-well service companies use devices which record the drilling rates automatically.

Electric, Radioactivity, and Other Logs

The well-sample examiner must rely on electric, radioactivity, and other mechanical logs for exact determination of lithologic boundaries. Certain constituents of the rock column may be lost in the drilling fluid and thus be poorly represented in the samples; others, such as fissile shales or gypsum, may appear in abundance by caving and thereby lead the microscopist astray. It is routine practice for experienced sample men to work always with one of these physical logs lying alongside the sample log strip and to check constantly the response of the electric or radioactivity curves to lithologic changes observed in the cuttings. As mentioned earlier, these logs must be used judiciously, for radical departures of the curves may have little or no bearing on lithologies; for example, a profound break in a resistivity curve may appear in a homogeneous sandstone where oil or gas rest upon salt water.

It is well to keep in mind that the electric and radioactivity logging devices are *geophysical* instruments. The records (logs) obtained are geophysical records, and they must be interpreted in a geologic or lithologic sense just as a seismogram must be interpreted in terms of geologic conditions or phenomena. It is always wise to study and compare the physical logs from nearby wells where lithologies have been determined from cores. Armed with such data, one can use the electric log empirically with some confidence.

Electric and similar logs are fully discussed in Chapter 14. It is advisable to study this chapter thoroughly before attempting to apply these logs in connection with lithologic determinations.

MEANING AND SIGNIFICANCE OF COLOR

Color is generally conceded to be one of the important attributes of a sedimentary rock, ranking in importance with composition, texture, structure, and other properties. In the process of teaching (and learning) the distinguishing properties of sedimentary rocks, diverse methods are employed toward attaining higher precision in the determination of these rock properties. Most of the properties have been reduced to specific terms, and standards have been set up to maintain consistent results in determinative work, as, for example, scales of hardness, tables of grain sizes, and percentages of mineral constituents. But the important property of color has received only desultory consideration. A very few workers have done some research on the subject, but the results of this work have failed to reach those who could put them to the most effective use.

In order to understand the significance of rock color, or even to describe the color, it is first necessary to understand a few of the fundamentals of color itself.

Colors observed in rocks under the binocular microscope may be considered as pigment colors or mixtures of the three pigment primaries—red, yellow, and blue. The rock color, as perceived, may be due to a single mineral whose color is a mixture of the primaries, or it may be caused by a mixture of a number of grains, each having a distinctive color of its own. The over-all effect of such a rock color may be quite different from the color of any one of the constituent grains. A rock whose color is distinctly brown may be seen under the microscope as a mixture of red quartz and feldspar grains and green glauconite grains. Red and green pencils matching the grain colors will produce the brown rock color when mixed in the same proportions on the log.

While the following brief discussion does not purport to be more than a mere introduction to one phase of the subject of color, it may serve to arouse sufficient interest to spur further investigation.

All colors possess three properties: hue, value, and intensity. These qualities are fundamental and must be understood if color perception is to be in any way analytical. The qualities of color mentioned are also known by other names, which are given, together with the definitions.

Hue

The hue of a color is its identity with reference to basic colors. Examples are red, red-orange, blue, blue-violet, yellow, yellow-green, etc. Colors such as olive,

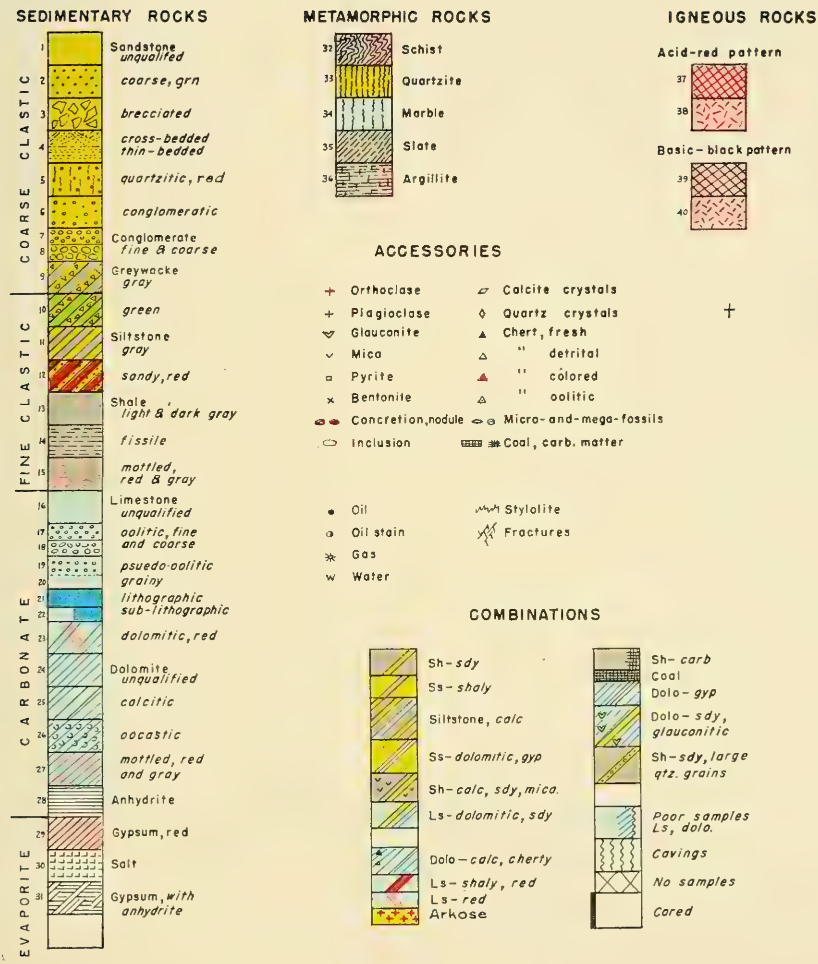

PLATE 3-I. Color chart for well log symbols. The basic lithology color for sandstones is yellow, but the color of the rock is shown by stippling, as in numbers 2 and 5. Only a few lithologic combinations are shown, although a great many additional ones may be indicated by the method illustrated. Occasionally, a new accessory symbol must be devised. The new symbol must not conflict with one already in use, but represent a dissimilar feature. Symbols not representing rocks or minerals, such as oil stains or water, should be plotted adjacent to, but not within, the lithology column. The same hues of blue and yellow must be used for carbonate and coarse clastic rocks; otherwise, the symbol might be confused with the color representation of certain shales.

rust, brown, and gray-brown are not hues. The hue of a color is not altered by the addition of white, gray, or black—the neutrals.

Value (tone)

The value or tone of a color is the degree of lightness or darkness. A red hue is not altered by adding white, but the value is changed. Values may be expressed in terms of neutral tones from black to white. Thus, a color, such as red, may have the same value as a dark gray, depending upon its degree of darkness. Colors of low value are called shades; those of high value, tints.

Intensity (chroma)

The intensity of a color is its purity. The intensity of color is reduced by the addition of neutralizing elements, such as gray or white. The intensity of rock color is generally low because of the presence of neutralizing agents, and the matching of rock color must take this fact into account.

If colored pencils in red, blue, and yellow closely approach the primary colors, almost any color can be obtained with them simply by mixing in various proportions; but in order to produce all tints and shades, the neutral factors must be added. The neutral "colors" in log work are made by lead pencils in several degrees of hardness or tones.

It was stated above that all colors possess three qualities; hue, value, and intensity. If the part each plays in producing the colors observed in rocks is understood, the rock colors will be more easily analyzed; hence, they will be more easily described and duplicated in whatever medium is used. A few illustrations of the fundamental properties will show their interrelationships and their individual effects on the colors observed.

A mixture of yellow and blue results in green. The proportions of the blue and yellow determine the hue. A small amount of yellow and a large amount of blue will produce a green-blue; if the proportions are reversed, the hue will be a green-yellow. The same principle holds for the orange group obtained with red and yellow, or the purple group obtained wth red and blue, as, for example, purple, red-purple, purple-blue, and the like. All these intermediates, as well as the primaries, are hues.

Starting with the hue orange-red in comparatively pure pigment, the value, or brightness, can be increased by the addition of white. The hue is not changed. When colored pencils are used, the value is raised simply by applying less color to the white paper. The value is lowered by adding gray pencil to the hue established with the colored-pencil mixture.

The intensity of color is its degree of purity or lack of neutralizing factors. The intensity of a color should not be confused with its value or brightness. For example, the pure orange-red hue has the highest intensity, but only medium

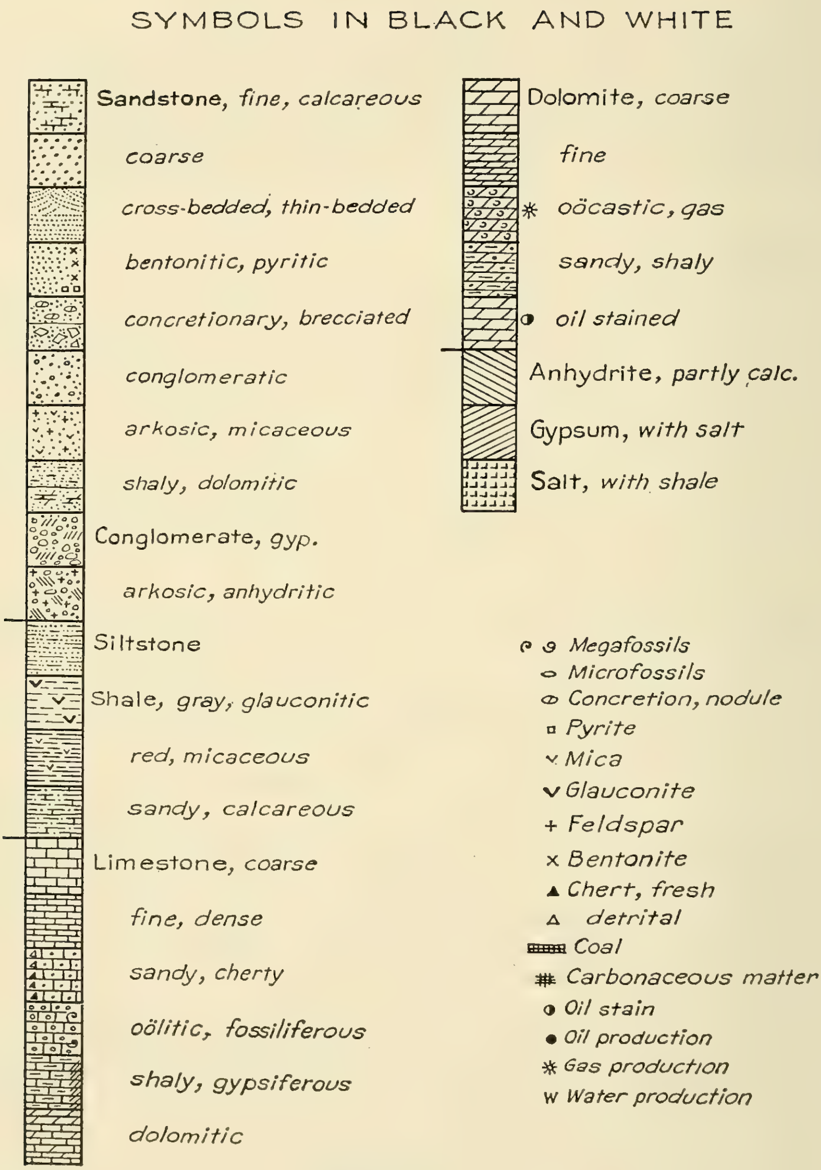
SYMBOLS IN BLACK AND WHITE
Sandstone, fine, calcareous
coarse
cross-bedded, thin-bedded
bentonitic, pyritic
concretionary, brecciated
conglomeratic
arkosic, micaceous
shaly, dolomitic
Conglomerate, gyp.
arkosic, anhydritic
Siltstone
Shale, gray, glauconitic
red, micaceous
sandy, calcareous
Limestone, coarse
fine, dense
sandy, cherty
oölitic, fossiliferous
shaly, gypsiferous
dolomitic
Dolomite, coarse
fine
oöcastic, gas
sandy, shaly
oil stained
Anhydrite, partly calc.
Gypsum, with salt
Salt, with shale
Megafossils
Microfossils
Concretion, nodule
Pyrite
Mica
Glauconite
Feldspar
Bentonite
Chert, fresh
detrital
Coal
Carbonaceous matter
Oil stain
Oil production
Gas production
Water production

Figure 3-8.

value, corresponding to an intermediate gray in the black-to-white neutral scale. Now if white is added, the brightness, also, is heightened, but the intensity is lowered because of the diluting effect of the white.

The value of a color—and only the value—may be referred directly to the neutral scale, black to white. A medium red corresponds to medium gray; a very light red (pink), to pale gray. The word tone is used when speaking of the brightness or darkness of grays; values refer to colors.

If the above facts are kept in mind, it is not difficult to duplicate rock colors by the use of very few pencils. The color maroon, which is often used to describe the color of certain shales, is simply a red hue of medium intensity and low value. To duplicate this color, one should apply a strong red color to the log. The value is raised because of the white paper (or the high value of the pencil); so gray of lower value than the red is added (pencil of about 2H hardness). The pink-lavender of some clays and shales employs the same red, applied lightly, but followed with a pencil of about 7H hardness, a light tone of gray.

Browns are composed of a mixture of the three primaries, plus gray. Since blue and yellow make green, it follows that brown is made also by mixing red, green, and gray. Different browns are obtained by emphasizing the intensity of one or more of the constituent colors; thus a red-brown emphasizes the red.

In pure, intense pigments, the three primaries cancel out when mixed in the right proportions, and the result is black. The colors in pencils are generally of such low intensity that black cannot be attained with them.

While it is not practicable for the sample examiner to match all rock colors by mixing red, blue, yellow, and gray, the principles discussed should be learned and applied. With a nominal amount of practice, the rock color can be duplicated within small limits with perhaps only eight pencils. It is often faster to mix two colors than to search for the right pencil. In a series of alternating orange-red shales and sandstones, yellow is first applied to the entire succession. The red is then used over the shale intervals to produce the desired color. Tan-gray shales and sandstones are colored in the same manner, except that a hard lead pencil is run over the yellow. Blue-gray shales and carbonates are made by running gray pencil over the blue in shale intervals. Many time-saving combinations will be discovered during the course of the work when the principles discussed are applied. Obviously, better work and higher production are the reward for acquiring a working knowledge of color, so that principles guide the worker in the use of this important rock character.

ABBREVIATIONS FOR LOG STRIPS

It is necessary to use many abbreviations in the lettered descriptions of well logs because of the limited space on the strip. Since there is no standard for the abbreviations of many words, a number of forms are in use. The fact that the list given here will no doubt conflict with some usages cannot be avoided entirely.

In a series of adjectives, the period normally used after an abbreviation may be omitted. Each period occupies the space of a letter, and the cumulative space in a line would be enough for one or two additional descriptive words.

Abbreviations for Log Strips

absorbed—abs
absorption—absp
abundant—abdt
accumulation—accum
agglomerate—agl
aggregate—ag
algae—algae
algal—algal
angular—ang
anhydrite—anhy
arkose, arkosic—ark
banded—band
barite—barite
bentonite—bent
biotite—bio
bituminous—bitum
black—bl
blue—blue
brachiopod—brach
brown—brn
brownish-gray—brn-gr., etc
brecciated—breccia
calcareous—calc
chalcedony—chal
chalk—chalk
chert—cht
chlorite—chlor
clay—clay
coal—coal, coaly
coarse—crse
colloidal—coll
conglomerate—cglm
conglomeratic—cglmtc
cream—crm
creamy—crmy
crystal—cryst, xl
crystalline—xln
dark—dk
darker—dkr
different, difference—diff
diffused—diffus
disseminated—dissem
dolomite—dolo
dolomitic—dolom
drab—drab
elevated, elevation—elev
fine, finely—fine, or f
flint—flint
fluorescence—fluor
fluorite—fluorite
fossiliferous—fossilif
fossils—fos
fusulinid—fusul
globular—glob
gradational—grada
grading—grad
granular—gran
gray—gr
green—grn
gyppy—gyppy
gypsiferous—gypsif
gypsum—gyp
hard—hd
igneous—ig
illite—illite
inclusion—incl
indurated—indur
interstices—interst
interstitial—interst
jasper—jasp
laminated—lam
large—lge
lavender—lav
lignite—lig
limestone—ls or lss
limonite—limon
limy—limy
little—lit
long—long
magnetite—mag
massive—mass
material—mat
matted—matted
medium—med
micaceous—mica
mudstone—mudst
muscovite—musc
olive—olive
oolitic—ool
opaque—op
opposite—oppos
orange—orange
orthoclase—orth
oxidized—ox
part—pt
phlogopite—phlog
phosphate—phos
pink—pink
pin point—ppt
plagioclase—plag
plastic—plast
pores—pores
porous—por
purple—purp
quartz—qtz
quartzite—qtzte
quartzose—qtzse
random—rand
red—red
round—rnd
rugose—rug
rusty—rusty
salt—salt
sand—sd
sandstone—ss, sss
sandy—sdy
saturated—sat
shale—sh
shaly—shy
siderite—sid
siliceous—sil
silt—silt
siltstone—sltst
slight—slt
slightly—sltly
sphalerite—sphaler
spicular—spic
stain—stn
staining—stng
subangular—subang
sucrosic—suc
sulphur—sulf
talc—talc
tarnished—tarn
tripolitic—trip
tubular—tub
undulating—undul
varicolored—varicol
variegated—varig
vermiculite—vermic
vuggy—vug
water—wat
white—wh
with—w
yellow—yel

Reprinted from Colorado School of Mines Quarterly, 1951, v. 46, no. 4.

Chapter 4

THIN-SECTION ANALYSIS

Russell B. Travis

Petroleum originates, migrates, and accumulates in rocks whose texture, structure, and composition permit or prohibit formation of oil pools. They determine which fluids will flow and the rate at which they will flow under given conditions. In view of their importance, it is unfortunate that detailed study of sedimentary rocks as a routine technique in surface and subsurface geology has been neglected for so long. Only in recent years have oil companies begun to realize that the petrographic microscope is more than a research tool and that it has effective application in the increasingly difficult search for petroleum.

Sedimentary rocks are as complex as igneous and metamorphic rocks and cannot be evaluated properly without petrographic microscopic studies. By using the microscope as routine procedure, oil companies are obtaining more accurate and meaningful information from exploration programs. The newest advance in sedimentary petrography is in subsurface petroleum geology, in which it not only aids well-to-well correlation, but can be used in planning exploration- and exploitation-drilling procedures. The purpose of this paper is to point out some methods that can be applied in this field. These methods fall into five general areas: (1) correlation, (2) lithofacies studies, (3) reservoir studies, (4) petrofabric studies, and (5) basement studies. Conventional thin sections, thin sections of well cuttings, and immersion oils can be used. The comments included here are brief, but references to more thorough treatment are given at the end of this chapter.

THIN-SECTION PREPARATION

The methods of thin-section preparation have not changed in the last 100 years, although the techniques have been improved. The main steps in preparing a thin section still include sawing a chip, cementing it to a glass slide, reducing it to proper thickness, and protecting it with a cover glass. With suitable equipment, thin sections may be prepared in nearly any size, 4 x 5 inches being not uncommon; but for most work, standard 26 x 45-millimeter petrographic slides are satisfactory. The equipment needed to prepare thin sections depends on whether mass or occasional production is desired. Except for research departments or for special projects, facilities for occasional production are adequate. Most thin sections are made now by professional men who can produce large numbers at a moderate price ($1.25-$1.75).

Reed and Mergner (1953) give a thorough account of thin-section preparation as followed in the United States Geological Survey laboratory. They also describe techniques used for special rocks and for repairing damaged slides. Meyer (1946) describes a method that involves sawing off as much of the excess material as possible after the specimen has been cemented to the slide. Rowland (1953) describes a method involving use of a surface grinding machine that has a vertically arranged diamond-impregnated grinding wheel. By this change from conventional horizontal-turning laps, sections can be ground faster and more accurately.

The equipment necessary for thin-section preparation includes a rock saw, grinding laps, hot plate, plate glass, and a polarizing microscope. A large variety of rock saws is available, but all are similar to the one shown in Figure 4-1. Although it is possible to prepare a thin-section with a single grinding lap, it is more efficient to have three or even four. Conventional laps have a horizontal turn and are mounted in basins to catch cuttings and excess abrasive material. The setup shown in Figure 4-2 is typical. Nearly any type of hot plate having a heat-control rheostat is satisfactory. A small plate has the advantage of heating and cooling quickly; a larger one may be better controlled. An ordinary plate glass will serve as a base for final grinding, but it must be discarded at the first sign of concavity. A polarizing microscope is required to determine proper thickness of the thin section (0.03mm), but one no longer suitable for regular petrographic work is usually adequate. Some of this equipment is shown in Figure 4-3. For those who desire compact, inexpensive equipment, combination machines that can be used for both sawing and grinding are available.

Friable sedimentary rocks must be impregnated with a binding material before being sectioned. Most rocks that are coherent enough to yield cores are

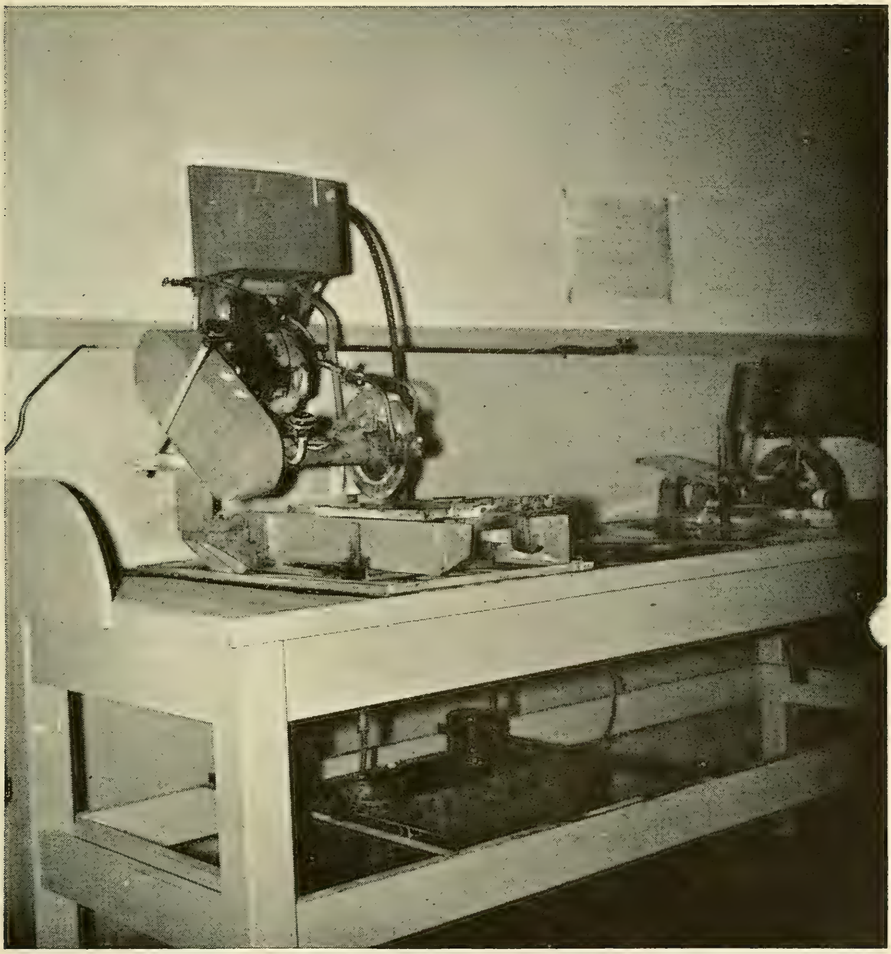

FIGURE 4-1. Conventional equipment for routine rock sawing.

sufficiently coherent for sectioning without impregnation. Routine impregnation of coherent rocks, however, may be desirable to preserve delicate features that sawing and grinding might otherwise destroy. Canada balsam, Dammar gum, Lakeside No. 70 cement, and various cold-setting plastics may be used. Satisfactory results usually require special treatment such as replacement of hot xylene with the impregnating medium by first moistening the specimen with kerosene (Von Huene, 1949) or by impregnating in a vacuum.

Thin-section data are often desired from uncored wells. Thin sections can be prepared from cuttings without the sawing required with core thin sections by mounting the cuttings directly in cement on a glass slide and then grinding to

FIGURE 4-2. Typical horizontal-grinding laps.

proper thickness. The various special treatments required depend on the lithology of the cuttings.

THIN-SECTION STUDY Most subsurface studies with the polarizing microscope involve examination of texture as well as composition, and they require thin sections from either cores or cuttings. The desired information, however, may often be obtained by using the oil-immersion method of mineral identification described in the final section of this chapter.

FIGURE 4-3. Equipment used in thin-section preparation. Hot plate, cements, abrasive, dispensers, glass plate, and microscope.

Routine Petrography

The most useful information in petroleum exploration and exploitation is basic data; an accurate record of the petrography of formations as well as their distribution and structure is becoming mandatory. In solving problems, the more complete and accurate the data, the more reliable are the interpretations drawn from them. Routine petrographic descriptions of thin sections can form a very valuable file, which can be readily and profitably applied to almost any

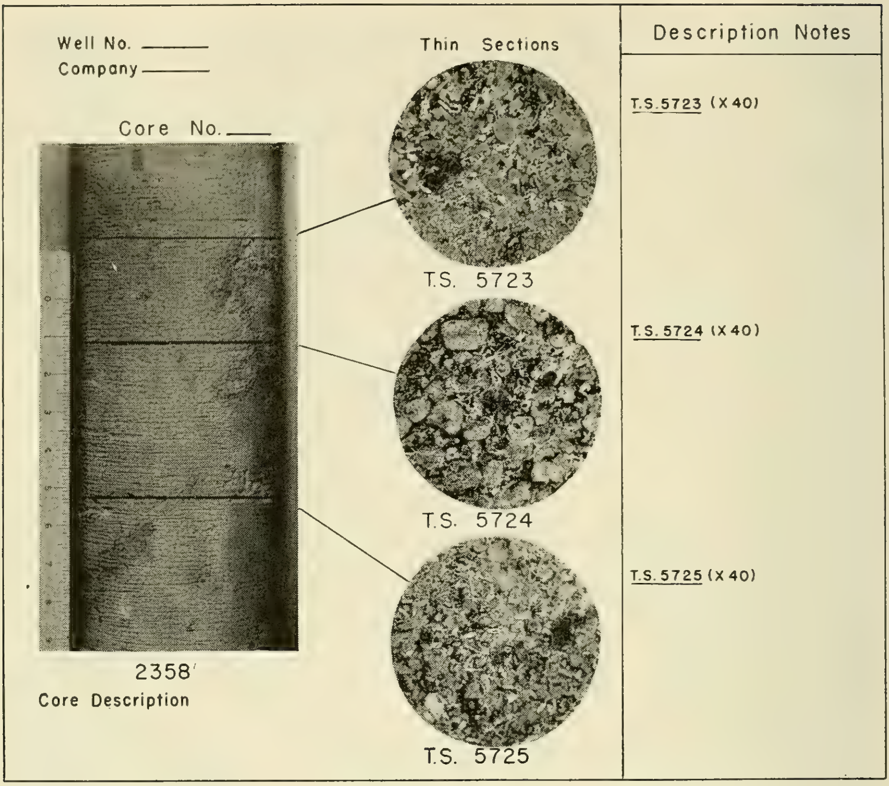

FIGURE 4-4. Example of photographic record of core and thin sections.

geologic problem. Very useful records of cores can be made by photographing both core and thin sections and mounting the photos in their proper relationship as illustrated in Figure 4-4. Routine petrographic descriptions of thin sections are especially valuable in gleaning all possible information from slim-hole exploration drilling.

Correlation

Thin-section studies have proved to be very helpful in correlating formations. Formations that may be indistinguishable in cuttings may often be distinguished petrographically. For example, the quartz of one sand may include a high proportion of strained grains, or one sand may be predominantly feldspathic and another lithic. Even shales may be distinguished by their sand or silt content. Chemical rocks can often be recognized by characteristic impurities. In any correlation problem, it must be kept in mind that sudden and extreme lateral and vertical variations in composition or texture within a formation are common. Thin sections often provide a critical means of correlation where other routine methods fail. Inasmuch as thin sections of cuttings can be prepared quickly, they can be used for routine formation identification during drilling.

Lithofacies Studies

Probably the most extensive use made of thin sections in subsurface geology at present is in lithofacies investigations. Many geologists believe that even subtle lithologic changes have profound influence on oil occurrence. A careful study, then, of these changes not only results in better control for selection of wildcat locations, but may actually aid in a development drilling program in areas having abrupt facies changes.

A word of caution is appropriate in this regard. Lithofacies maps are only as reliable as the data on which they are based. Useless and even detrimental maps can result from inaccurate analysis or from careless or inconsistent nomenclature in rock classification. Care should be taken to see that studies are done accurately and that, for the map area, the elements of description and nomenclature are consistent. The number of different elements that can be used in lithofacies studies is too great for consideration here; however, some of the more common general elements may be outlined.

Cement Versus Matrix

The kind of interstitial material in a detrital sediment might have an important bearing on the migration and accumulation of fluids. Two significantly different kinds of interstitial material are chemical material or cement, and detrital material or matrix. The conditions by which cement or matrix are produced are profoundly different and most likely have an influence on the origin of petroleum. The shifting in relative proportions of cement and matrix, either laterally or vertically, might prove a useful criterion in a given area. Plotting these data might reveal trends that correlate with better producing characteristics or, in some other way, increase development or exploration prospects.

Amount of Interstitial Material

The amount of interstitial material in a sediment is a very important element to consider. It not only largely determines porosity and permeability but may have genetic significance, which in turn may correlate directly with petroleum occurrence. Detrital interstitial material is always contemporaneous with deposition of the major fraction, whereas chemical interstitial material may be either contemporaneous or post-depositional. The movement and accumulation of fluid within rocks then, must be affected profoundly by the amount and relative age of interstitial material.

Studies of the amount of interstitial material may be made with various degrees of accuracy. For some purposes, a visual estimate of half a dozen different slice areas may be sufficient. For a detailed micrometric treatment of quantitative model analysis of thin sections, one may refer to Chayes (1956). In most detrital sediments, there are no sharp breaks in sorting; therefore, if the interstitial material is detrital, an additional problem arises.

How can the interstitial material be sharply distinguished from the major fraction? One approach is to select a size arbitrarily and to check the close grains with a micrometer eyepiece. If the sorting is very poor, it is not practical to pursue this kind of study; it is better to use screen analysis, provided disaggregation is possible.

Kind of Cement

The kind of cement or relative proportions of different kinds may be plotted advantageously on maps. The same agents that influence petroleum movement may also influence cementation. Under such conditions, changes in cement directly reflect conditions that improve or weaken chances of finding petroleum. The most common cementing materials are calcite, dolomite, quartz, and chalcedony. In certain areas, evaporite minerals, phosphate minerals, or iron oxides may be common. Knowledge of slight changes in composition, such as the proportion of iron in ankeritic dolomite, may prove useful.

Rock Composition

Composition of the rocks is one of the most commonly used parameters in lithofacies studies. An infinite number of variables in chemical as well as detrital sediments can be mapped in this way. Gradual or abrupt changes from limestone to dolomite, gypsum to anhydrite, quartz sand to feldspathic sand, or red beds to gray beds are all equally useful for lithofacies studies. Few geologists question the value of maps based on variations in composition. It is beyond the scope of this paper to discuss the possible correlations between composition and petroleum occurrence. Clay minerals, by virtue of their composition and small grain size, are very active chemically. They not only influence petroleum distribution but are exceedingly important in drilling and production practices. Clay minerals, however, can be handled in thin section only in a general way; other study techniques are more applicable (Grim, 1953). Many changes in composition lead to textural changes that may be of critical importance.

Grain-Size

Because petroleum migrates through and collects in rock spaces, any condition affecting these spaces (size, shape, distribution) is important. Texture in sediments generally has not received the attention it warrants. More careful consideration should be given to grain size in all routine examinations of rocks. In thin section, diameters of grains, for the most part, are apparent diameters rather than true diameters. The apparent average is less than the true average size. This difference depends on such factors as grain size and relation of section to bedding. The coarser the grain, the greater is the difference. Most sediments of interest are moderately fine-grained and satisfactorily lend themselves to thin-section study. A micrometer or grid eyepiece affords the most convenient method of making grain-size measurements. Screen analyses normally yield the best results for grain-size studies and should be used where practicable.

In lithofacies studies, consistent nomenclature is important, particularly in textural investigations. For example, in the preparation of a sand-shale ratio map, the criteria for distinguishing sand from shale must be defined clearly and consistently followed, especially in regional studies that may involve the work of several lithologic groups. The amount of silt that determines whether a rock is called shale or siltstone must be decided arbitrarily. Sand-shale ratio maps are very commonly prepared from electric logs. Thin sections provide a means of evaluating the electric-log profile against the lithology.

Diagenetic Changes

In the migration and accumulation of petroleum, some of the most important controlling factors are those changes that occur after or during deposition. These changes (excluding metamorphism) are collectively termed diagenesis. Certain processes such as compaction and cementation are lithifying diagenetic processes, whereas others, such as leaching or replacement, are nonlithifying diagenetic processes. These processes not only may limit or trap the flow of petroleum but may conceivably force petroleum from one place to another. Here again, processes that may cause changes in composition may bring concurrent textural changes. Some of the parameters that can be mapped are compaction, recrystallization, cementation, leaching, and replacement.

Metamorphic Changes

The distinction between diagenesis and metamorphism is somewhat arbitrary. Generally, the concept of metamorphism includes the influence of elevated temperature and pressure. Diagenetic changes, on the other hand, are believed to occur at temperatures not much different from those at the surface. The beginning of metamorphism is indicated by the development of certain diagnostic minerals or by changes in fabric. Near regional metamorphic terranes or contact metamorphic terranes adjacent to igneous intrusions, the distribution of petroleum may be critically affected by degree of metamorphism. In a given area, it might be possible to determine the lithofacies criteria by which favorable and unfavorable areas could be delineated. The trends established by plotting thin-section data on signs of metamorphism could prove very helpful in an exploration program.

Reservoir Studies

In recent years, encouraging results have focused considerable attention on reservoir engineering. The increasingly important problem of recovery is one involving the characteristics of the reservoir. In view of the fact that oil reservoirs are in rocks and that the best way to study rocks is in thin section, it follows that efficient study of reservoirs must include study of thin sections. Although quantitative analysis of porosity and permeability is better accomplished by other means, thin sections provide a means of studying other equally important features of the reservoir, such as type of porosity, composition as affecting wettability, and texture as affecting tortuosity.

Porosity patterns in rocks are very complex, more complex than is generally realized. Although the main types of porosity are intergranular, fracture, and cavity, there are many different variations in each; therefore in evaluating porosity of carbonate rocks especially, one must consider each rock individually. In phaneritic detrital sediments, porosity is normally intergranular. In aphanitic detrital sediments and chemical sediments, porosity is normally of the fracture or cavity type. A highly indurated sandstone, however, may have the same kind of porosity as chemical rocks. A thorough treatment of porosity in petroleum reservoirs is given by Levorsen (1954).

Determination of the kind of porosity is important because porosity determines to a large degree the response of a rock to treatment in completion or secondary-recovery practices. Many good examples of the part thin sections can play in solving these problems are given in a recent paper by Waldschmidt, Fitzgerald, and Lunsford (1956). In their summary they state, "The importance of the phases of petrographic research here described can not be overemphasized, especially as related to the selection and improvement of treating processes, initial and remedial, and also as related to the estimation of reserves, secondary recovery problems, and problems of stratigraphy."

Depending on the degree of lithologic detail and accuracy desired, several thin sections from the same sample may be required. Slices should be cut in different directions to portray the three-dimensional aspects of the rock. The original spaces and grain relationships may be made more conspicuous by impregnating the specimen with dyes.

Two of the most important factors in fluid transfer through rocks are: (1) the attraction between rock and fluids, and (2) the surface area of the channels along which the flow takes place. Both of these factors must be considered in reservoir analysis. For given pressure-temperature conditions, the attraction between rock and fluid depends on their respective compositions. The fluids may be readily analyzed, but thin-section study is required to identify the minerals in the rock. The other factor, surface area, is directly related to grain size and grain angularity. The ratio of porosity to surface area is of critical importance. The advantages of determining these factors are that on the basis of rock composition, a suitable detergent may be selected without time-consuming trial-and-error methods. From textural analysis, the most efficient rate of withdrawal or displacement of fluid may be estimated.

Universal Stage Techniques

The universal stage greatly extends petrographic investigations in that it permits study of pertinent features that are beyond the capacity of the normal

FIGURE 4-5. Setup for universal stage work.

petrographic microscope. The fundamental advantage of the stage is that a thin section can be oriented to almost any position. In addition to standard petrographic equipment, only a 3- or 4-axis stage and a net for plotting are necessary to carry on this work (fig. 4-5). Some suggestions for application of the universal stage to sedimentary petrography and a bibliography of the general technique appear in a paper by Gilbert and Turner (1949). Some uses of the universal stage which are applicable to subsurface petroleum geology are discussed below.

Mineral Identification

The universal stage has several advantages over the normal thin-section method of mineral identification. With the universal stage, one can determine the relationships between optical and physicial properties. With only the microscope, it is often impossible to find grains oriented so that all optical properties can be determined. With the stage, it is possible to tilt the section so that most and often all the properties of a single grain can be determined. In Gilbert and Turner's paper, a method is outlined for distinguishing some of the carbonate minerals in thin section. The universal stage is a powerful easy-to-use tool that should not be neglected in detailed rock analyses.

Miscellaneous Textural Studies

Because it is possible to orient a thin section with the universal stage, many textural features otherwise unobserved become visible. Grain contacts can be studied to ascertain whether they are normal depositional, intergrown, or otherwise interfered. Whether grain angularity is due to abrasion or to authigenic outgrowths can be determined because outgrowths are less difficult to recognize with the stage. Where multiple cements are present, it is often possible to determine the order of deposition. Many cementing materials develop crystal faces during deposition. These faces are frequently preserved when a subsequent cement is deposited. By determining relations between the optical properties and the crystal faces, it is possible to establish to which mineral the face belongs, thereby establishing a genetic relationship. This method is described by Gilbert and Turner (1949).

Petrofabric Analysis

One of the most important uses of the universal stage involves petrofabric analysis, or determination of preferred orientation of grains. When rocks are formed in, or subsequently subjected to, an anisotropic environment—one that does not have the same properties in all directions—there is a tendency for the rocks to reflect the anisotropy. This condition is more conspicuous in some rocks than in others; and in many environments, the anisotropy is too weak to induce measurable effects. However, many rocks do possess anisotropic features derived from their environments. Some of these features are clearly visible to the unaided eye—for example, foliation in schists. Others are detected only by statistical analysis with the universal stage.

Petrofabric analysis consists of systematically traversing a thin section and plotting positions of selected elements. The most commonly used elements are the optic axis of quartz, poles to cleavage of mica, poles to twinning of lamellae, and optic axes of carbonate minerals. Anisotropic fabrics may be either of depositional or of deformational origin. Inequant grains tend to be aligned under the influence of current. If the current was strong and the grains pronouncedly inequant, the anisotropy may be readily apparent. If the current was not so strong, or the grains not so inequant, the anisotropy may be detected only statistically. Even quartz grains are slightly inequant, elongate along the *c*-axis. Plotting the positions of these axes frequently demonstrates preferred orientation. This technique can be used in channel deposits to ascertain direction of former stream flow.

In a similar fashion, preferred orientations may be developed during deformation. When a simple fold is formed, there is a tendency for mineral grains to orient themselves with certain directions parallel to the axis of folding. A statistical study of the fabric of a specimen may reveal its relation to the structure and indicate the trend of the fold axis at that point.

Basement-Rock Studies

Thin-section studies in subsurface petroleum geology should not be limited to sedimentary rocks. Valuable and often critical information may be gained by thin-section studies of basement rocks. The circumstances under which these studies may be profitable fall into several categories.

Recognition of a rock as a basement type may require thin-section examination. Occasionally wells have been bottomed far short of basement by misidentifying or misinterpreting the penetrated rock. Determination that a rock is of plutonic igneous or of metamorphic origin is generally sufficient to indicate basement. One of the most common errors in the past has been the belief that all quartzites are metamorphic. Actually many quartzites originate by the normal sedimentary process of complete silification of a quartz sandstone. In their gross features, these quartzites do not differ from metamorphic quartzites; however, metamorphic quartzites can be recognized by the presence of metamorphic minerals or a crystalline texture as contrasted to clastic texture.

Volcanic rocks, including pyroclastics, do not necessarily indicate basement, and therefore, should be distinguished from plutonic igneous rocks; however, intensely hydrothermally altered volcanics, often called greenstone, generally constitute basement. Although fresh granitic rock is usually recognized without much difficulty, arkose and altered granitic rock are difficult and sometimes impossible to distinguish even in thin section. Many arkoses have a vague clastic texture that can be recognized, whereas granitic rock, though many of the grains may be considerably altered, still retains its crystalline texture.

Locally, oil reservoirs occur in basement rocks. Some of these, such as those in weathered zones, have a general equidimensional distribution. Others, such as those in shear zones or in certain beds of metasediments, have a linear distribution. The prospects for additional locations in either of the linear reservoirs can be improved greatly by attempting to determine the trend of the structure controlling the reservoir. This evaluation can be improved by petrofabric analysis of oriented cores. In addition, study of the type and distribution of basement rocks may yield valuable information about subsurface structure.

OIL-IMMERSION METHOD OF MINERAL IDENTIFICATION

The best procedure for mineral identification is the oil-immersion method. The main advantages of this method are (1) preparation of a thin section is unnecessary; (2) determination of refractive indices is possible; and (3) relationships between optical properties and physical properties, especially cleavage, can be determined. The main disadvantage is that grain-to-grain relationships and texture cannot be determined. For this reason, the oil-immersion method cannot totally replace the thin-section techniques. The method consists essentially of immersing crushed mineral grains in oils of known refractive index. Most of the optical properties are determined as they are in thin section, and only the oils are needed in addition to standard petrographic equipment.

Although cleavage aids in identifying minerals, it presents problems in measuring principal indices of refraction. For example, rhombohedral cleavage causes calcite grains to lie with their *c*-axes inclined to the stage at a high angle. The extraordinary index can be determined only when the *c*-axis is horizontal; therefore it is necessary to tilt the grain to the proper lie in some way. A universal stage can tilt the slide. This tilting can also be accomplished by propping up a grain with surrounding smaller grains; or, if the inclination of the *c*-axis can be determined from an interference figure, the extraordinary index can be calculated from the measured partial extraordinary index. Biaxial minerals can be handled in the same manner. For many common minerals having good cleavage, such as the rhombohedral carbonates and plagioclase feldspars, values for the indices on cleavage fragments are available (Winchell, 1951; Taylor, 1948).

The oil-immersion method should not be discounted simply because index oils are not available. This method has other important advantages than index determination. Cleavage and its relationship to optical elements can be determined, and preparation of material for examination is simple and rapid. Several common oils, such as clove oil, may be used for the immersion medium. Even with one oil, some index information can be obtained; that is, one can determine whether the indices of the mineral are less or greater than that of the oil, and whether the difference is small or great.

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Chapter 5 INSOLUBLE RESIDUES

H. A. Ireland

An insoluble residue may be defined as the material remaining after rock fragments have been digested in acid. Hydrochloric acid is generally used, but acetic acid is occasionally used if the preservation of delicate fossils or other structures is desired. Residues, such as shale, pyrite, gypsum, anhydrite, and glauconite, are not siliceous; therefore, the term siliceous residues cannot be applied correctly. The chief residues are quartz and various types of chert, with chert the most diagnostic for identification and correlation.

McQueen (1931) and Martin (1931) published methods of preparation, terminology, and practical application of insoluble residues to surface and subsurface correlation and identification of calcareous rocks. The work of Martin is not known so well as that of McQueen although it is a significant contribution. Ireland (1936) expanded the application of insoluble residues to a regional basis by correlating outcrops in the Arbuckle Mountains through the subsurface to outcrops in northeastern Oklahoma and adjacent areas. The use of insoluble residues was not widespread prior to 1938. After 1940 rapid advances were made with the application of residue work to petroleum geology. The United States Geological Survey and many state surveys now have numerous publications based wholly or in part on insoluble residue work (for a comprehensive list of publications and active workers who have not published see Ireland, 1947). A diversity of nomenclature resulted because most of the residue work in Texas was developed without reference to that of McQueen. In 1946 Ireland called a conference of active workers on insoluble residues. This conference resulted in the publication of a standardized terminology and a chart for description (Ireland, 1947), which is published herein in a modified form (see Table 5-I)

PREPARATION OF RESIDUES

Types of Samples

The materials treated for insoluble residues are well cuttings, cores, and outcrop samples. The most desirable outcrop samples are channel samples or a composite mixture of each exposed stratum within a 5-foot or other close-spaced interval. Point-to-point correlation is rarely possible, because there is very little probability of sampling exactly the equivalent point some distance away. A 6-inch layer outcropping within a 5-foot interval will not represent the whole interval, and it cannot be correlated with the equivalent interval a mile away, which may have a 6-inch layer exposed a foot above or below the one in the first outcrop. Only zones or intervals may be correlated successfully. Outcrop samples of unweathered chips, without lichen, soil, or other extraneous matter, are desirable.

Oil- or water-well cuttings and cores are the most widely used materials for residues. Cable-tool cuttings are the best samples, because they contain a minimum amount of caved material and because each sample represents a composite of the rock within the sampled interval.

Rotary-tool cuttings are the most common well samples and are generally the only type of samples available from deep wells. They are also the worst samples. Caving is very common because long sections of the drill hole are not cased. If shale beds or loosely aggregated materials lie above a given sample, caving may reduce the amount of indigenous material of the sample to such a small percentage that an insufficient amount of residue or none will be left after solution. Such samples may require the use of forceps for picking out chips of the indigenous material for solution. Drilling time, electric logs, and a thorough knowledge of the section facilitates the identification of the indigenous material.

Well cores must be split and a fragment taken from each inch or short interval; and the whole must be mixed for the equivalent of a 5-foot sample, or for a shorter interval if the lithology changes. Otherwise, inconclusive point-to-point correlation would be necessary.

The observable amount of indigenous material in a sample having 80 to 90 percent shale caving may be increased by placing two or more unit volumes of the sample in acid, and, after solution, sieving out as many unit values less one. Thus, if three units were used, two units would be sieved out after solution. This will leave less than one unit volume, which will have a minimum amount of caved material but several times more residue from the indigenous

TABLE 5-I

CHART FOR INSOLUBLE RESIDUES

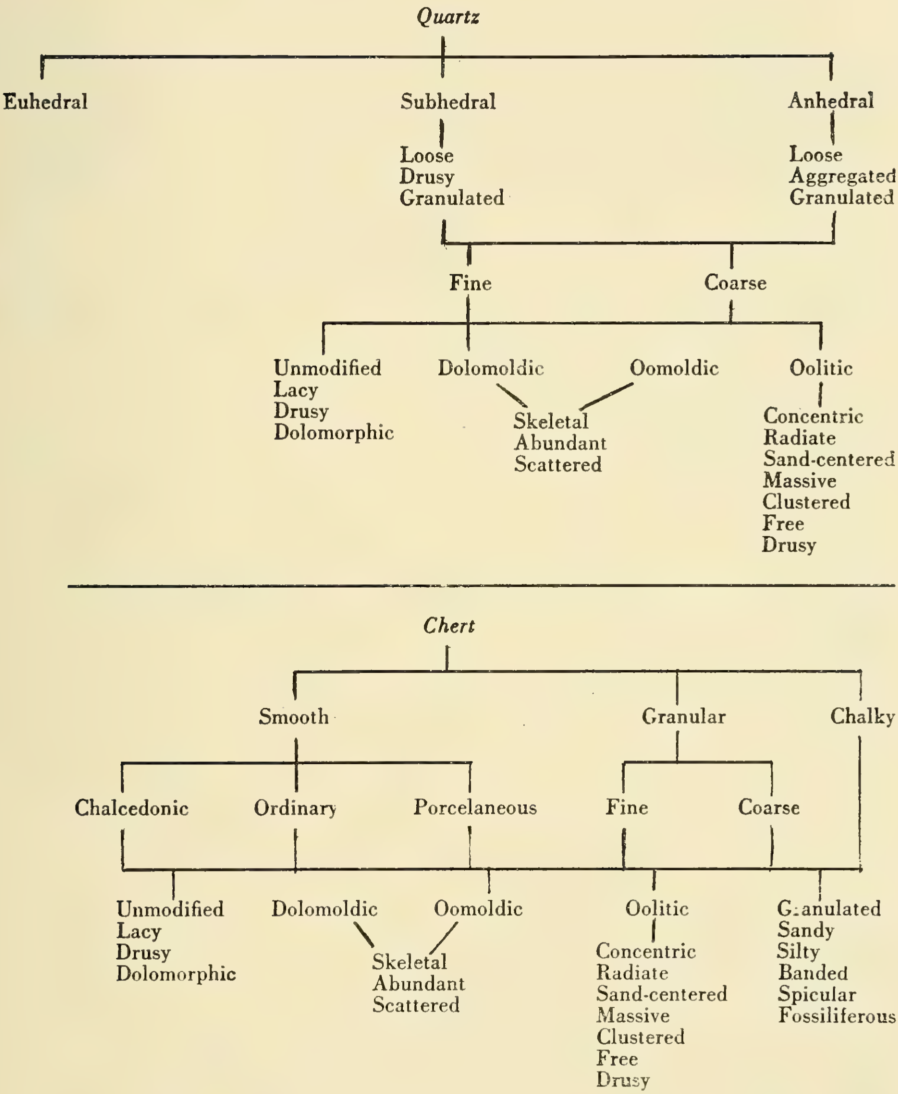

TABLE 5-I—Continued

Argillaceous material

- Clay
  - Spongelike
  - Flaky
  - Massive
- Shale
  - Smooth
    - Flaky
    - Waxy
    - Laminated

(Spongelike, Flaky, Massive, Shale)

- Unmodified, Lacy, Dolomorphic
- Dolomoldic, Oomoldic
  - Skeletal, Abundant, Scattered
- Oolitic
  - Concentric, Radiate, Sand-centered, Massive
- Sandy, Silty, Fossiliferous, Glauconitic, Pyritic, Micaceous, Other minerals

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Arenaceous material

- Silt
  - Loose
  - Consolidated
    - Poorly
    - Well

  (Loose, Poorly, Well)

  - Fossiliferous, Sandy, Quartzose, Glauconitic, Pyritic, Micaceous, Other minerals
  - Dolomoldic, Oomoldic
    - Abundant, Scattered
  - Oolitic
    - Concentric, Radiate, Sand-centered, Massive
- Sand
  - Loose
  - Consolidated
    - Poorly
    - Well

  (Loose, Poorly, Well)

  - Rounded, Subrounded
    - Frosted, Polished, Etched
  - Angular, Regenerated

Anhydrite

- Massive
  - Fine, granular
    - Subhedral
    - Anhedral
  - Coarse aggregates
- Fibrous
- Subhedral
- Anhedral

Gypsum

- Massive
- Fibrous
- Selenitic

Unclassified Accessory Residues

Sulphur, pyrite, marcasite, sphalerite, millerite, magnetite, hematite, limonite, feldspar, muscovite, biotite, chlorite, glauconite, barite, celestite, other insoluble minerals, fossils, pellets, beekite material. Large fragments of chert or other insoluble material considered indigenous may be picked out with forceps from the sieve and added to the residue.

Amount of Sample

The volume or weight of sample used to make a residue depends on the purpose of the study, the type of samples used, and individual judgment. Seven grams is an ample amount of sample for ordinary uses. This weight is an average for the volume contained in a one-dram vial, 45 by 15 millimeters. The same volumes of 10 different homogenous samples ranging from very fine to very coarse fragments of limestone, shale, sand, and chert were weighed, and the average of 7 grams was determined. The volume-weight of 7 grams reduces considerably the time for the preparation of residues. Small samples of less-than-unit volume must be weighed if percentage determinations are desired. The use of a small scoop sized for a unit volume or a tip balance saves time.

Many workers do not use percentages, but the percentages of residue are valuable in many instances for correlation and identification of beds. Samples from rotary tools can rarely be used satisfactorily for percentage determinations unless caving intervals have been cased.

Siliceous limestone, tripolitic or cotton chert, and calcareous shale may lose up to half their weight but retain unit volume after solution. Such samples should be weighed before and after acidification, if the percentage of residue compared to the original volume is needed. If the volume of the vial is used as the unit of the original sample, the percentage of nonporous residues may be scaled or observed through the glass vial. Pure limestone or dolomite samples from cores or outcrops may leave only a few grains of residue, and it may be necessary to use 2, 3, or even 5 units of the original sample to obtain sufficient residue for examination and determination.

Solution of Samples

Samples are generally dissolved in commercial hydrochloric (muriatic) acid. It is inexpensive, easily obtained, and effective. The acid should be diluted with water to at least 50 percent but to no less than 10 percent. Warming will hasten the reaction, but undesirable precipitates may form. Many complex reactions occur between caved material, constituents of the indigenous material, and the impurities in the muriatic acid. Iron, gypsum, and other precipitates, in many instances, coat, stain, and contaminate many types of residues. Many samples will not dry clean if left in the spent acid and precipitates longer than 6 to 8 hours.

Chemically pure (CP) hydrochloric acid has advantages for special work where outcrop samples are used, where precipitates or impurities are undesirable, or when solution is extended over several days. Acetic acid is best for liberation of delicate, fragile, lacy material or for microscopic organisms. Delicate residues may be preserved by using very dilute hydrochloric acid, but the time required for solution is lengthened.

Beakers are the best receptacles for solution of the samples. They are preferred because the lip facilitates washing and decanting, residues may be easily removed, and a glazed spot is provided on the side for identification of each sample. Molded tumblers or other cheap glassware may be used, but the breakage due to heat while drying samples equals or exceeds the greater original cost of heat-resistant glassware.

The procedure for residue preparation is simple. Samples of unit quantity are placed in a glass receptacle properly identified on a slip of paper under a pyrex dish or by any consistent regular arrangement. Samples are then digested in acid, washed, dried, labelled, and stored for examination. The use of several stainless-steel trays, or other type of tray holding 40 to 50 beakers, facilitates the bulk movement of samples to the hood for acid application, washing, drying, or other operations involving the handling of large numbers of samples.

The first application of acid should be small to prevent foaming caused by the rapid effervescence of powder and fine material. The foaming may easily cause the overflow and loss of considerable material. A few minutes after the initial application, additional acid may be added, but only experience will tell how much, generally not more than one third to one half the capacity of the receptacle. After several hours of digestion, the samples should be washed once or twice to remove spent acid, precipitates, and undesirable material. The second application of acid will generally complete the digestion, although one application may be sufficient. Small applications of acid will digest samples which obviously are chert, sand, or shale. Incomplete digestion will leave dolomite pellets with rough, jagged surfaces and rounded pellets of limestone. When samples are incompletely dissolved, individual euhedral dolomite rhombs may be a large part of the residue. Final washing should be thorough to remove all traces of acid and prevent scum, caking, or coating on the residues.

Clay and fine silt are generally decanted in routine work. Little or no work has been done with the fine residues, and their value for correlation and identification is yet to be determined. Perkins worked a year with the fines and developed procedures to eliminate flocculation, but he found them too involved and time-consuming for practical purposes. Petrographic study of the fines require special equipment and give only academic results. He concluded, as others have previously, that only the percentage and general physical properties of the fines had any diagnostic value. Only outcrop or core samples can be used for a study of the clay and silt residues, because caving and other contamination of well samples obscure diagnostic features and make uncertain the identification of indigenous fine clastic material.

Residues may be dried in an oven, on a hot plate, or on a sand bath. Dry residues are brushed into a pan or funnel for transfer into glass vials, which may be labelled on the cap, cork, or a paper sticker. Permanent storage requires a painted label or glazed surface on the side of the vial, because silverfish enjoy eating the glue from stickers. One-dram vials hold ample residue for study and require very small storage space. Trays, drawers, original vial boxes, or special boxes are suggested methods of storage.

DESCRIPTION OF RESIDUES The most common insoluble residues are chert, chalcedony, disseminated silica, clastic and crystalline quartz, aluminous matter, and replaced fossils. Anhydrite, gypsum, feldspar, glauconite, hematite, pyrite, fluorite, and sphalerite are the most common minerals, but other insoluble minerals are found.

Table 5-I is a modified arrangement of the original chart published with the paper on standardized terminology (Ireland, 1947). The terminology is based on description rather than genesis of the residues because genesis of many constituents is unknown, vague, or controversial. Many possible types of residues are given a place in the table, although their existence has not been confirmed. Each term is clear-cut and restrictive, and within certain limits a residue fragment may be pigeonholed. It should be emphasized that types of residues grade into other types, and, as some specific fragments may not be easily placed, workers may place a fragment under a different but related type in the classification.

TERMINOLOGY FOR INSOLUBLE RESIDUES Definitions of special terms as agreed upon by the Residue Conference of 1946 are given below in alphabetic order.

Abundant dolomolds or oomolds: See "dolomoldic."

Anhedral: No crystal form developed.

Beekite: Botryoidal, subspherical, or discoid accretions of opaque silica replacing organic matter, generally white.

Chalcedonic: Transparent to translucent; smoky; milky; waxy to greasy; may be any color, generally buff or blue-gray; may be finely mottled.

Chalky: Uneven or rough fracture surface; commonly dull or earthy; soft to hard; may be finely porous; essentially uniform composition; resembles chalk or tripolite. (Formerly referred to as "dead" or "cotton chert." This includes dull, unglazed porcelaneous material which grades into glazed porcelaneous material of smooth chert.)

Chert: Cryptocrystalline varieties of quartz, regardless of color; composed mainly of petrographically microscopic fibers of chalcedony and/or quartz particles whose outlines range from easily resolvable to nonresolvable with binocular microscope at magnifications ordinarily used by geologists. Particles rarely exceed 0.5 mm in diameter.

Clay: Fine material of clay size.

Clustered: See "oolith."

Concentric: See "oolith."

Dolomold: Rhombohedral cavities in an insoluble residue. (Generally due to the solution of euhedral dolomite or calcite crystals.)

Dolomoldic: Containing dolomolds.

> Skeletal with dolomolds: Residues with rhombohedral openings in which the constituent material comprises less than 25 percent of the volume of the fragment. Openings vary from microscopic to megascopic.
>
> Abundant dolomolds: Residues with rhombohedral openings with the constituent material comprising from 25 to 75 percent of the volume of the fragment. Openings vary from microscopic to megascopic.
>
> Scattered dolomolds: Residues having rhombohedral openings in which constituent material comprises more than 75 percent of the volume of the fragment. Openings vary from microscopic to megascopic.

Dolomorphic: Used for describing residues where there has been replacement or alteration of dolomite or calcite by an insoluble mineral which assumes the crystal form of the soluble mineral, thus filling a dolomoldic cavity.

Drusy: Clusters or aggregates of crystals, generally incrustations.

Euhedral: Doubly terminated crystals; unattached.

Free: See "oolith."

Granular: Chert; compact, homogenous; composed of distinguishable relatively uniform-size grains, granules, or druses; uneven or rough fracture surface; dull to glimmering luster; hard to soft; may appear saccharoidal. (This type is frequently referred to as "crystalline.")

Granulated: Grains or granules partly cemented or loosely aggregated; saccharoidal; grades from angular to drusy; fine to coarse; particles rarely larger than 0.5 mm in diameter.

Lacy: Residues with irregular openings in which the constituent material comprises less than 25 percent of the volume of the fragment.

Massive: See "oolith." Used also to include fine or coarse granular anhydrite or gypsum.

Mottled: Residue fragments with two or more colors or different material interspersed and irregularly shaped with the boundaries between either sharp or gradational; often appears flocculated; grades into speckled residue.

Oolite: Composed of an aggregation of ooliths.

Oolith: Spheroidal bodies with nucleus or central mass enclosed by one or more surrounding layers of the same or different material; may be any color and of many kinds of material, generally less than 1.0 mm in diameter. Those over 2.0 mm are pisoliths.

Concentric: Peripheral layers around a small, undetermined nucleus.

Clustered: Attached ooliths without solid matrix.

Drusy: Oolith covered with subhedral quartz; may be free or clustered.

Free: Unattached oolith.

Massive: Interior of granular, smooth, or chalk-textured material comprising nearly the entire mass of the spheroid.

Radiate: Fibers radiating from small or large nucleus; may have several peripheral layers.

Sand-centered: Nucleus, a quartz sand grain.

Oomold: Spheroidal opening representing the former presence of ooliths.

Oomoldic: Containing oomolds.

Skeletal with oomolds: Same definition as for "dolomoldic."

Abundant oomolds: Same definition as for "dolomoldic."

Scattered oomolds: Same definition as for "dolomoldic."

Ordinary: Smooth chert with even fracture surface; all colors, chiefly white, gray, or brown; may be mottled; approaches opaque; generally homogeneous, but may have slight evidence of granularity or crystallinity; grades into chalcedonic or granular chert.

Porcelaneous: Chert with smooth fracture surface; hard; opaque to subtranslucent; typically china-white resembling chinaware or glazed porcelain; grades to chalky.

Pseudoolithic: Rounded pellets with no peripheral layers or sharp distinction between pellets and matrix.

Pyrimolds: Cavities left after the removal of euhedral pyrite by weathering or otherwise.

Quartz: Clear, colorless quartz; not detrital.

Radiate: See "oolith."

Regenerated: Used in reference to quartz sand grains with secondary regrowth of crystal faces oriented with the original axis of the grain.

Rounded: Spheroidal or ellipsoidal sand grains, coarse to fine, may be polished, frosted, or etched.

Sand: Grains of sand size, chiefly quartz, but may be composed entirely or partly of other minerals.

Sand-centered: See "oolith."

Scattered: See "dolomoldic" and "oomoldic."

Silt: Grains of silt size, chiefly quartz, but may be composed entirely or partly of other minerals.

Skeletal: See "dolomoldic" and "oomoldic."

Smooth: Major type of chert with conchoidal to even fracture; surface devoid of roughness; may be botryoidal; homogeneous; no distinctive structure, crystallinity, or granularity.

Speckled: Disseminated fine spots of color or material different from that of the matrix and having relatively sharp boundaries.

Spicular: Containing inclusions of sponge spicules. Free spicules have been noted.

Subhedral: Crystal forms partly developed; may be loose, drusy, or granulated.

Subrounded: Polygonal grains or fragments but with well-rounded edges and corners.

Unmodified: Residue uniform with no modifying characteristics.

The most common residues are chert and sand, with chert rated as the most diagnostic. Texture, color, transparency, luster, and crystallinity are the chief factors for the diflerentiation of chert. Inclusions and modifying characteristics are secondary factors. Chalcedonic and ordinary chert are the most abundant of the smooth cherts. The term granular chert is applied to obviously crystalline chert or that with observable grains. Smooth and granular cherts grade into each other and into chalky chert. The chalky types are those of which the original internal structure and filled interstices have been affected by weathering and probably by circulating water. Tripolitic chert when placed in acid leaves a very fine, porous, chalky chert because of the solution of disseminated calcium carbonate. All the cherts may be dolomoldic, the dolomolds ranging in type from scattered to skeletal and in size from fine to very large.

The color of chert is an important diagnostic feature. It is prevalently colorless, white, gray, tan, and brown, but all colors are found. Many residues from beds in Missouri, Kansas, Oklahoma, and Texas have sudden color changes which mark boundaries of zones or formations. The smooth brown chert of the Lower Devonian in West Texas is difficult to differentiate from that in the Upper Ordovician, and drilling to an underlying boundary is necessary in many places for positive identification.

Organisms may be replaced by silica or other insoluble matter and may be identified in the residues, especially small forms and foraminifera, which generally are not broken by the drill. Molds of organisms are common where soluble shells or fragments have been imbedded in an insoluble matrix. Beekite occurs most commonly in replaced megascopic fossils found in outcrop samples.

Quartz may be euhedral and authigenic or subhedral and anhedral from veins, cavity filling, or interstitial openings. Quartz sand of various types from rounded to angular may be found as scattered inclusions or as a dominant feature in a sandy calcareous rock. Secondary enlargement or regrowth of quartz crystals around sand grains is a common occurrence in the Lower Paleozoic. The crystal growth in some sandstones is distorted and interlocked with adjacent grains in such a manner that a tight, nonporous formation results. Feldspar, mica, glauconite, and other minerals are common as residue constituents of sandstone, althought quartz is the chief constituent. Calcareous material interstitially mixed with very fine quartz in silt and clay sizes results in a very fine porous residue.

Glauconite is abundant in sands and is scattered throughout many calcareous beds. It is a good marker for many beds in the Paleozoic, chiefly in the Mississippian, Middle Devonian, Middle and Lower Silurian, and Upper Cambrian. Few of the Lower Ordovician Beekmantown beds have glauconite, and the appearance of glauconite generally marks the top of the Cambrian.

Pyrite is a common insoluble residue seen as small to large, euhedral crystals in limestone, dolomite, and shale. It also occurs spongelike, disseminated, and in veins and cavities. Pyrite has little value as a diagnostic residue, but it has a secondary value as an inclusion in chert or shale. When pyrite occurs in abundance, it may serve as a marker bed and often identifies a zone of circulating water or an unconformity.

Interstitial spaces due to primary or secondary permeability, alteration, or replacement in calcareous rocks may become filled with silica, pyrite, or other insoluble material. Solution of the matrix leaves fragile, lacy networks that are generally destroyed by acid effervescence and washing. These residues are the extreme upper limit of skeletal dolomolds, pyrimolds, and oomolds. Residues from veins or fractures are curved or tabular flakes. Vein fillers or cement for brecciated residues include gilsonite, silica, pyrite, and sphalerite.

Siliceous limestones have residues that are generally earthy, finely porous, and dark-colored. These residues are especially noteworthy because examination of such samples before solution gives no clue to the type of residue. The residues from siliceous limestone also appear to be 100-percent insoluble by volume, but they may be 50-percent insoluble by weight, owing to the removal of the interstitial lime.

Siliceous oolites are common and may be found free, clustered, or in a matrix. An oolite, to be identified as such, must have a nucleus and at least one concentric layer or shell. Nuclei may range in size from very minute to one occupying nearly all of the interior mass. Most ooliths have several shells. Ooliths are classified according to the interior structure as concentric, massive, radiate, or sand-centered. Clustered or free ooliths may be frosted with a crust or minute drusy quartz or may have a smooth, siliceous shell. Silica may replace calcareous ooliths and cause them to be preserved as residues. Ooliths have many colors and in many instances occur embedded in different-colored matrices. All types of chert have ooliths, although in chalky chert they are rare.

Chert in many instances has included sand grains, which may be confused with ooliths. Shells are absent, however, and the clear quartz of the said grain may be observed.

Pseudoolites or shadow oolites resemble oolites and may resemble quartz sand grains. The boundary between the matrix and the oolith is indistinct, however, and the central portion, which cannot be identified as quartz is only a shade lighter or darker than the other portions. Pseudoolites may be ooliths or sand grains that have been resorbed, thus destroying any formerly existing boundaries.

Dolomolds occur chiefly in chert residues from dolomites, rarely in chert from limestone. Dolomolds are common in shale residues and are present in some pyrite and glauconite residues. Natural dolomclds resulting from weathering are common on certain types of outcrop samples. In dolomite, the dolomolds are assumed to be the impressions from dissolved dolomite rhombs, but in shale the cavities are likely to be a result of dissolved interstitial calcite. Disseminated abundant fine dolomite or calcite crystals in chert, silt, or shale will leave a very finely porous residue, too fine to be observed except under high magnifications. The residue of a sample with large quantities of dolomite rhombs will have an intersecting lacework of fragile skeletal dolomolds, whereas a sample with a few rhombs will leave scattered dolomolds in the insoluble matrix. Dolomolds may be large or small, but generally all in any one fragment will be essentially the same size.

USE OF INSOLUBLE RESIDUES

The study of insoluble residues is a supplement to and not a substitute for lithologic sample examination. The cost of preparing and filing residues and the longer time necessary for the more detailed and careful examination of them are factors that must be considered. The mass characteristics of the major constituents of insoluble residues generally have enough similarity horizontally and vary enough vertically to serve for identification and correlation of lithologic units within a thick section of calcareous rock.

Lithologic similarities of thick sections of nonfossiliferous calcareous rocks prevent their subdivision into thinner zones for more detailed correlation and identification and structural mapping. Insoluble constituents having diagnostic characteristics may be obscured by the volume of the fragments in a lithologic sample and by being embedded in a solid matrix. These constituents are liberated, concentrated, and exposed by solution of the matrix. Diagnostic material such as foraminifera, some types of chert, dolomolds, disseminated pyrite, fossil replacements, euhedral crystals, mineral or clastic inclusions, and silt aggregates are not observed or recognized until they become residues.

Residues reflect clastic conditions, sea-bottom environment, current action, and adjacent land-mass conditions that may supply various types of source materials. These factors may change independently over short or long periods of time. If the source of material and the conditions of deposition or precipitation of calcareous matter remain fairly constant for a long time, no significant lithologic variations would result that might serve to identify a stratum. A slight change involving the source, type, or amount of clastic furnished to a lime-depositing environment might not affect greatly the lithologic appearance of a sediment, but such material when left as a residue would be diagnostic and would serve for correlation and identification. The amount of silica, iron, or salts in the sedimentary basin might change and give pyrite, siliceous limestone, various types of chert, and other minerals or constituents of diagnostic value—all of which might be independent of clastic material or changes in land-mass conditions or source material.

Circulating water and replacement and alteration of constituents before and after lithification would change the original residues. These changes, if of sufficient magnitude, might be observed in a lithologic examination of samples, but only the study of residues would show the small changes that might be useful in a detailed subdivision of beds. Correlation using residues of secondary origin could only be used locally or as far as the effect of the modifying conditions could be traced.

Correlations for distances greater than 50 miles are risky, unless some significant wide-range constituent can be determined, because the residues will change as the sedimentary environment changes. Obviously correlation using any specific zone of residue types would be less reliable in a basinward or landward direction than it would be laterally in a right-angle direction.

Correlation of individual thin beds may be difficult because of lateral and verticle changes within the sedimentary environment. The subdivision of a thick calcareous section and the inclusion of nondiagnostic thin beds into zones make correlation possible. Identification of the zones is based on such factors as sequence of beds, position in the section, percentage of residue, association of types of residues, and dominant characteristics with chief reliance on dominant characteristics. A distinctly significant residue may identify certain zones, although other residue constituents may be present, and even though the diagnostic residue is not the dominant one. An assemblage of residue constituents often determines the correlation or identification just as an assemblage of fossils serves for determination. Both microscopic and macroscopic fossils replaced with insoluble material are valuable in some zones.

Positive identification of some subdivisions is difficult with only a few samples, unless a significant break or change in residue occurs within the interval examined. For example, assume that a limestone 1400 feet thick is divided into 6 zones having intervals of 350, 100, 200, 400, 300, and 50 feet. It only ten 5-foot samples were available from zone 1 at the top, it would be difficult or impossible to identify their positions in the zone, although the zone itself could be identified. If the samples overlapped into zone 2, then the boundary could be recognized, and it could be stated that 300 feet or more of zone 1 was absent.

Many cherts are alike in color and texture, and similar cherts in two different zones would prevent identification, unless an associated residue was diagnostic or a zone boundary was passed. The similarity of the brown, smooth chert in the Lower Devonian and the Upper Ordovician in West Texas has been mentioned previously. If a chert in zone 1 was similar to a chert in zone 4 in the section postulated in the last paragraph, the two zones could easily be confused. If the set of 10 samples was identified as belonging to zone 1, but actually zones 1, 2, 3, and part of 4 had been eroded, an error of at least 650 feet in correlation would result. The correct identification of zone 4 would show a structural upfold. If the samples were identified as zone 4 and the producing bed was zone 2, the absence of zone 2 would be concluded and deeper drilling prevented.

The foregoing discussion shows the necessity of having some associated diagnostic residue or a zone boundary included in the sample interval for positive identification. Knowledge of the similarity of two zones would call for careful drilling and a postponement of identification until the underlying zone was encountered. With lithologic examination no zones could be identified.

Pyrite, regenerated sand grains, a sandy chert or sandy zone, a shale break, or other detritus often present clues to a formational change, which is some cases can be confirmed by other evidence.

The use of residues is not restricted to the laboratory. A microscope, a jug of acid, and a half-dozen beakers may be carried to the field. Water from a drilling well may be used for washing, and heat from an automobile-engine head or a drilling rig will dry the samples for examination on location. Obviously, a geologist attempting such work must be familiar with residue zones and sequences, as the necessary samples for comparison may not be available.

New workers with residues should be well aware that successful correlation by residues comes only after a thorough knowledge of residue types, principles of secondary replacement, and facies changes and the examination of many samples. Experience with residue material is prerequisite to the successful correlation and identification of beds. Of course, the foregoing statement is true for lithologic examination, but an inexperienced geologist can soon learn the surficial characteristics of rock fragments and correctly correlate, but he would find it difficult to correlate with residues without experience or the supervision of one experienced in residue work.

The use of residues for correlation has been successful in the thick calcareous sections of most Paleozoic rocks but has had little success in the thick Permian section of West Texas and New Mexico. Residue work has been especially useful in subsurface work and petroleum geology in Texas, Oklahoma, Kansas, Missouri, and Illinois and has contributed much to geologic science in the states between the Appalachian and the Rocky Mountains. The beds receiving the most attention have been Upper Cambrian and Lower Ordovician, but Silurian, Devonian, and Mississippian beds have been extensively studied.

The space allotted here would be inadequate to give worth-while descriptions of the subdivisions of the thick sections of calcareous rocks in the various parts of the United States. Anyone concerned would profit more to confer with workers familiar with local areas and sections.

Insoluble residues for paleontological studies have not been as widely used as they could be. Much very valuable information may be obtained regarding environments, population distribution, and morphology (Ireland, 1956). Obviously the method is limited to arenaceous foraminifera, phosphatic structures, siliceous radiolarians, diatoms, sponge spicules, and other forms whose parts are insoluble in hydrochloric or acetic acid. The residue technique is most fruitful with micropaleontology. Most microscopic forms which are too small to see when embedded, must be liberated for observation. Most forms found in the residues are clean, unweathered, unbroken, and otherwise undamaged. The loss of specimens is minor, and their recovery is simple when contrasted to the treatment necessary to recover forms from shale or clays. Many new forms and previously unknown evolutionary changes have been discovered from study of the insoluble residues of calcareous beds.

The extensive and successful application of residues to petroleum geology proves the value of residue studies, but few petroleum geologists have published results. The Insoluble Residue Library of Midland, Texas, is financed and operated by a dozen or more companies, which employ specialists for residue examination or subscribe to a special service furnished by the Midland Residue Research Laboratory. The Missouri Geological Survey uses insoluble residues as a standard procedure for the correlation of formations older than Pennsylvanian; its collection of residue samples is probably the largest and the finest in the world. The state geological surveys of Illinois, Kansas, Missouri, Oklahoma, and Texas and the United States Geological Survey have utilized the study of residues as a regular part of their programs for subsurface work.

PLOTTING RESIDUE DATA AND DESCRIPTIONS

The symbols and overprints given in Figure 5-3 are recommended for standardized use. They are essentially those used originally by the Missouri Geological Survey; but certain modifications, combinations, and additions make it conform to the standardized terminology. The symbols now used by the Missouri Geological Survey may be found in Grohskopf and McCracken (1949), and a typical log published by McCracken (1955) show a few modifications of the earlier published set. Color was used formerly by the writer

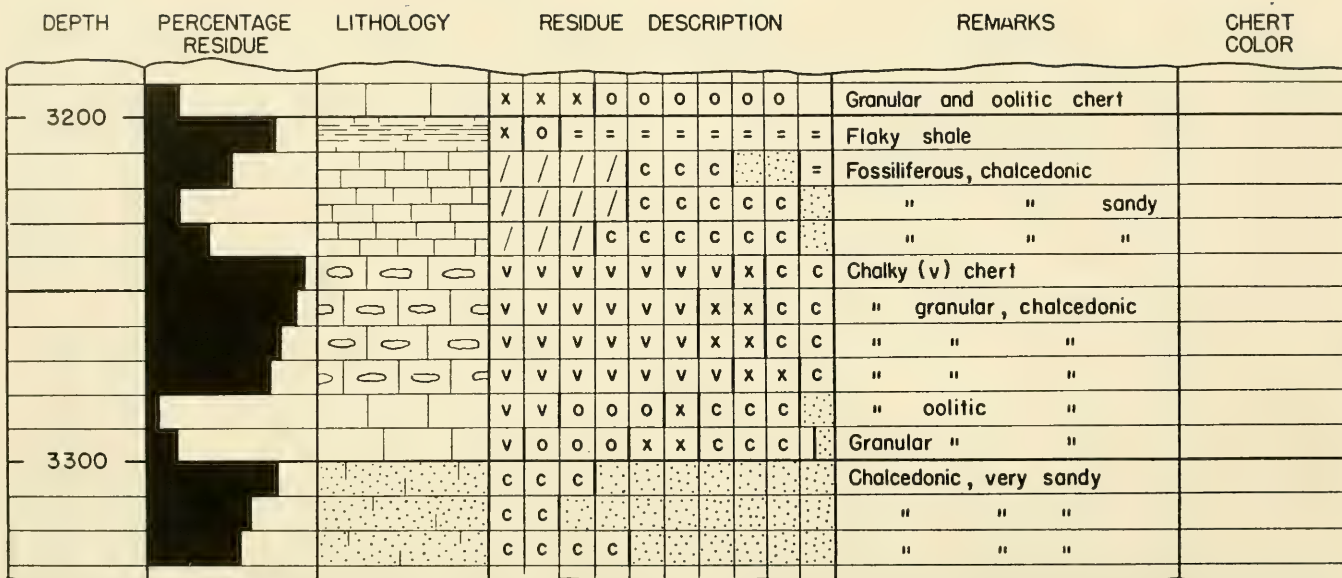

FIGURE 5-1. Constituent-percentage method of plotting residue data.

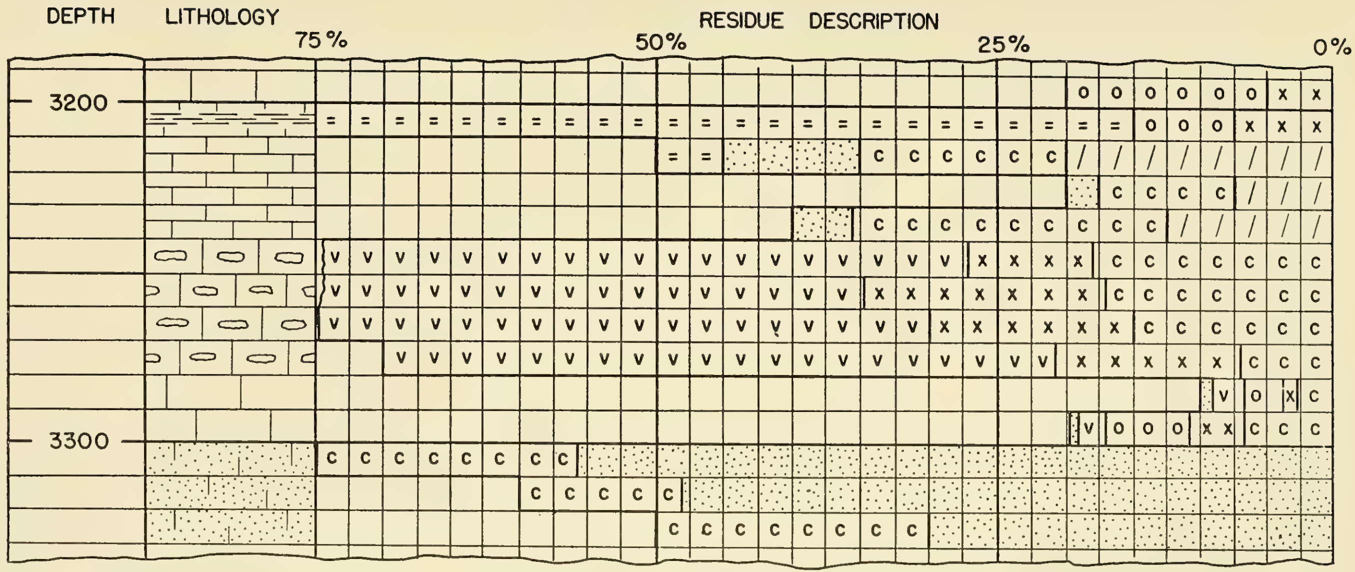

FIGURE 5-2. Percentage-percentage method of plotting insoluble residues. Plotting is based upon the same data and the same section as in Figure 5-1.

to indicate the observed color of the chert; but color is now used to indicate the type of chert, and the color of chert is indicated in a separate column.

Hendricks (1940) uses a set of letters, lines, bars, or graphs without color. If the percentage of the residues, the color of the residues, or the percentage of the constituents is not desired or necessary, the set of symbols used by Hendricks is adaptable. Many of them may be made with a standard typewriter.

Many methods of plotting residue data have been devised for individual needs and purposes. Three will be discussed here. The writer uses a method called the constituent-percentage method which is illustrated in Figure 5-1. The data and description are plotted with a grid ruling printed on a strip log 100 feet to the inch. This scale allows the comparison of residue logs with standard oil-well logs or sections. Other intervals may be used according to the need and desire for detailed description.

Column 2 shows the percentage of residue in relation to the original sample, and column 3 shows the lithology. The percentage of each constituent in reference to the total residue is plotted in column 4. Thus the percentages of the constituents from a 10-percent residue of the original sample will be shown in the same lateral space as the percentages from a 90-percent residue. Color and symbols with superscripts and overprints in ink over the colored background in column 4 describe and distinguish the constituents. The most specific information for correlation work appears in this column. Lines representing the color of the cherts are placed in column 6, the color being the same as the actual color of the chert, except that white chert is designated by green.

The percentage-percentage method is a second method of plotting. By this method the percentage of each constituent is plotted in proportion to its percentage of the original sample as shown in Figure 5-2. Superscripts and overprints in ink and color similar to the first method are used for differentiation of the constituents. An expanded scale is required and percentages over 75 are eliminated.

Residues from all types of samples may be plotted satisfactorily by this method except rotary-tool samples having considerable cavings. The caved material in rotary-tool samples hinders accurate judgment of the percentage of any one constituent in relation to the indigenous portion of the original sample. In all samples, the data for percentage-percentage plotting must be calculated, or a table must be used. A major disadvantage of the method is that a constituent which is 10 percent of a residue, which in turn is 10 percent of the original sample, requires the plotting of a 0.01 space on the log. Such a small space is difficult to plot as well as to identify in later study and correlation work. Though a 10-percent residue is ample for determination, many residues are less than 5 percent. Small but significant and diagnostic constituents would be obscure and very difficult to differentiate on a log. This method of plotting has an advantage in showing the percentage relations of the constituents at a glance,

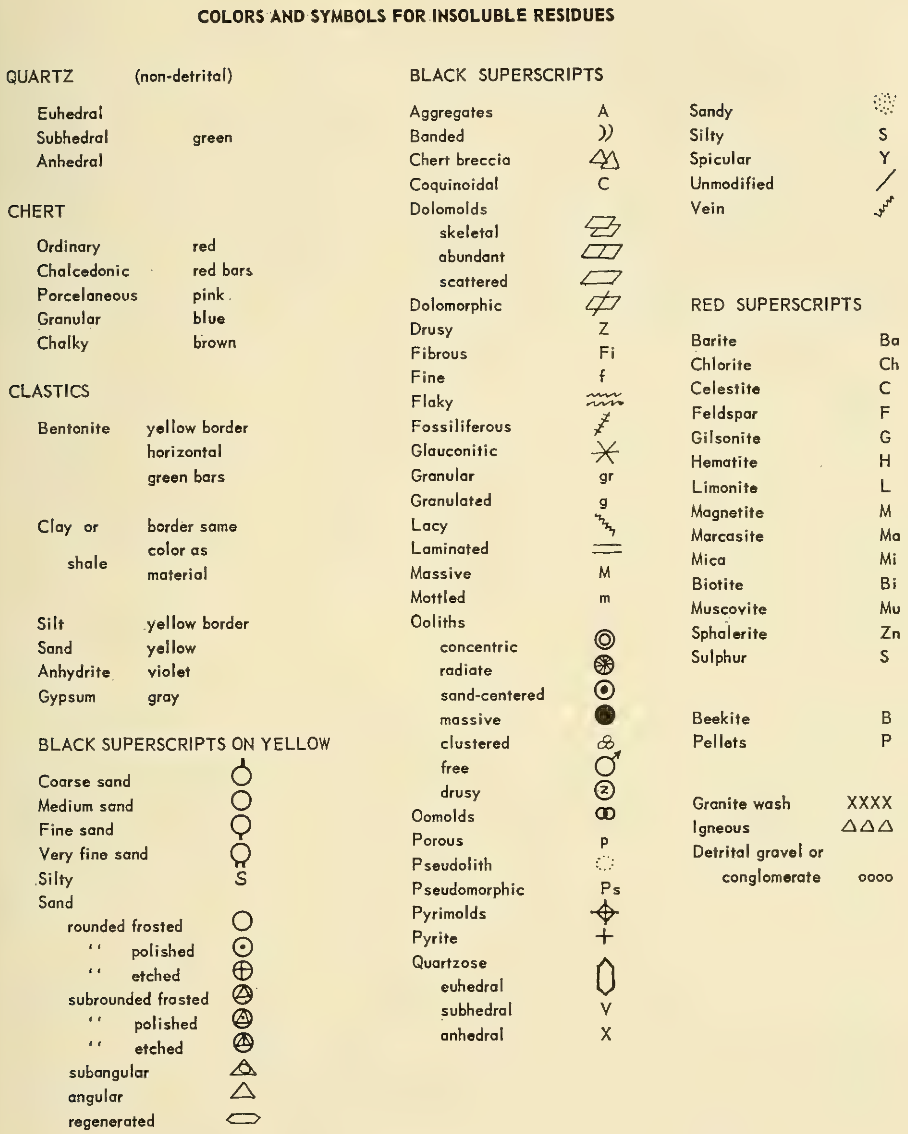

FIGURE 5-3. Colors and symbols for insoluble residues.

eliminating the examination of both the percentage and constituent columns of the first method discussed.

The third method of assembling data is a tabulation. A number of columns, headed by the names of significant types of residues, allow space for tabulating the percentage of each constituent and for symbols with superscripts or abbreviations added as modifying descriptions. This method is not suitable for correlation work and cannot be used in conjunction with the standard scale of plotted logs. It is useful only for tabulating data for the use of log plotters or others making strip logs or for consultation when detailed information not amenable to log plotting is needed.

The first method has been found to be the most satisfactory; and it is recommended, although several versions of the three have been used, and other combinations may be devised. It is most desirable for all workers to use a standard set of symbols, superscripts, and overprints. This applies especially to new workers entering the field of insoluble residues. Workers could then examine, discuss, interpret, and publish insoluble-residue correlations and identifications with a common background. Many workers will find it difficult or unwise to change systems of graphic description, because consistence with former usage is necessary where logs or records are involved.

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Chapter 6

MISCELLANEOUS PETROLOGIC ANALYSES

John R. Hayes

The purpose of this chapter is to present a brief summary of methods applicable to better evaluation of clastic and non-clastic rocks, in terms of their classification and interpretation of conditions under which they were deposited. More accurate classification of sedimentary rocks aids materially in all stratigraphic analysis procedures and should be the goal toward which geologists direct their interest.

SIZE ANALYSES

A basic property of clastic sediments is the size of the component particles. To evaluate this variable, one must determine the range and relative abundance of various size groups. In a clastic sediment the variation in particle size is continuous, and to study and classify the rocks, arbitrary groups are established. An analysis consists of measuring, in some manner, the range and relative abundance of particles in the groups selected. Statistically, it is the determination of the size-frequency distribution of the particles in a sediment.

Purpose of Size Analyses

The purposes of size analyses according to Pettijohn (1949) are as follows:

1. Improvement of classification and precision of nomenclature of clastic sediments.

2. Study influence of grain-size distribution on porosity and permeability.

3. Study of relations between dynamics of stream flow and transportation of particulate materials.

4. Quantitative studies of facies changes and correlations.

5. Identification of agent or environment responsible for the origin of the sediment.

From the above it is apparent that size analyses are essential in the study of clastic sediments. Complementing other data they frequently aid in the solution of many stratigraphic problems.

Equipment

Equipment normally required for size analyses is listed below:

(a) A set of nested sieves, the scale of which may be either the Tyler or the U. S. Standard. Table 6-I gives the comparison of these two scales and correlates them to the Wentworth size classification most commonly used by sedimentationists. The combination of sieves used will depend upon the sediment and the number of size groups desired.

(b) A balance for weighing samples and sieve fractions. An ordinary beam balance accurate to 0.01 gram is satisfactory.

(c) An assortment of 250- to 600-milliliter beakers.

(d) A rubber-tipped pestle or small wooden blocks for disaggregation of samples.

(e) A hand lens or binocular microscope for checking completeness of disaggregation.

If the sediment cannot be disaggregated because of the cementing material, thin sections must then be prepared. The grains are counted and measured with a petrographic microscope equipped with a mechanical stage and a micrometer eyepiece. If the sediment contains an appreciable amount of clay and silt particles, it may be necessary to subdivide this fraction. The equipment and procedures used in the analysis of clay and silt particles are discussed by Krumbein and Pettijohn (1938) and Twenhofel and Tyler (1941).

Other equipment that will aid materially in size analyses is a rock crusher, sample splitter, electric oven, and a Ro-Tap shaking machine. The ultra-sonic cleaner used to clean tools and machine parts has been found to be very useful in the disaggregation and cleaning of samples. (Gude, A. J., *U. S. Geological Survey,* personal communication.)

TABLE 6-I
Comparison of Sieve Grades

Tyler Sieves Mesh	Tyler Sieves Opening in mm	U. S. Sieves Mesh	U. S. Sieves Opening in mm	Wentworth Classification
3½	5.613	3½	5.66	Boulder, over 256 mm
4	4.699	4	4.76	Cobble, 64 to 256 mm
5	3.962	5	4.00	Pebble, 4 to 64 mm
6	3.327	6	3.36	
7	2.794	7	2.83	Granule
8	2.362	8	2.38	2.0 to 4.0
9	1.981	10	2.00	
10	1.651	12	1.68	
12	1.397	14	1.41	Very Coarse Sand
14	1.168	16	1.19	1.0 to 2.0 mm
16	.991	18	1.00	
20	.833	20	.84	
24	.701	25	.71	Coarse Sand
28	.589	30	.59	0.500 to 1.0 mm
32	.495	35	.50	
35	.417	40	.42	
42	.351	45	.35	Medium Sand
48	.295	50	.297	0.250 to 0.500 mm
60	.246	60	.250	
65	.208	70	.210	
80	.175	80	.177	Fine Sand
100	.147	100	.149	0.125 to 0.250 mm
115	.124	120	.125	
150	.104	140	.105	
170	.088	170	.088	Very Fine Sand
200	.074	200	.074	0.0625 to 0.125 mm
250	.061	230	.062	
270	.053	270	.053	
325	.043	325	.044	Silt 0.0625 to 0.004 mm
400	.038	400	.037	Clay less than 0.004 mm

Preparation of Sample

The size of sample to be used is discussed in Catalogue No. 53, published by W. S. Tyler Company (Cleveland, Ohio).

> The general rule in determining the size of a sample is that it be limited in weight so that no sieve in the series used in the analysis be overloaded. Overloading is most likely to occur in making analyses on closely graded materials where the range of particle size is confined to close limits. In this case the size of sample should be determined by the capacity without overloading of the sieve retaining the largest amount of sample. Overloading of the sieves results in unreliable data as blinding of the meshes occurs on the heavily loaded sieve.

The Tyler catalogue recommends 25 to 100 grams for closely graded materials. Krumbein and Pettijohn (1938) suggest 25 grams, whereas Twenhofel and Tyler (1941) prefer 40 grams. A review of current literature indicates that many workers use 50 to 100 grams. The screen diameter must be considered in selecting the weight of sample to be used. It is assumed that, where sample weights have been suggested, the weights recommended are for the standard 8-inch screens. Obviously the weight used on an 8-inch screen should not be used on a 3-inch screen.

In general, the type of cementing material governs selection of the disaggregation process; therefore, it is recommended that each sample be tested first to determine the most logical method of disaggregation. For example, dilute hydrochloric acid treatment aids in disaggregation of calcareous sands. Soaking in water will often break down argillaceous sands. Grinding with a rubber-tipped pestle can be attempted, but should be minimized to avoid excessive grain breakage.

If the sample contains an appreciable amount of clay and fine silt particles, it is best to remove this material because it has a tendency to form small pellets of clay and silt which will be retained on the coarser meshed screens. The fine material may be removed by decanting or wet sieving on a 250-mesh screen. The fine particles should be retained and added to the material passing the 250-mesh during the regular sieving process.

Separation Procedure

After the sample has been dried and weighed, it is placed in the nested screens and shaken by hand or in a mechanical shaker such as the Tyler automatic Ro-Tap. Ten to fifteen minutes in a mechanical shaker usually gives consistent fractionation. The material retained on each screen then is weighed and recorded. Often a slight weight loss is noted after shaking. This loss is attributed to grains adhering to the screens and fine particles lost as dust. If the sample is principally sand, the weight error may be proportioned among the various screens; however, if the sample has a high clay-and-silt content, the largest loss will be usually in this size range.

The screens should be cleaned thoroughly after running each sample by tapping the rim of the screen. If many grains remain in the mesh, gentle rubbing with a moderately stiff brush will dislodge most of them.

Table 6-I shows that the Tyler 250-mesh or the U. S. 230-mesh screens mark the dividing line between very fine sand and silt. It is common practice to use these screens as the smallest in the series and to catch the silt and clay particles in the lower pan. If there is considerable silt or clay, these particles then may be separated into size groups by one of the various methods outlined by Krumbein and Pettijohn (1938) and Twenhofel and Tyler (1941).

Presentation of Results

The results of size analyses are tabulated as shown in Table 6-II. From these data, histograms and cumulative-frequency curves (figs. 6-1, 6-2, and 6-3) are prepared.

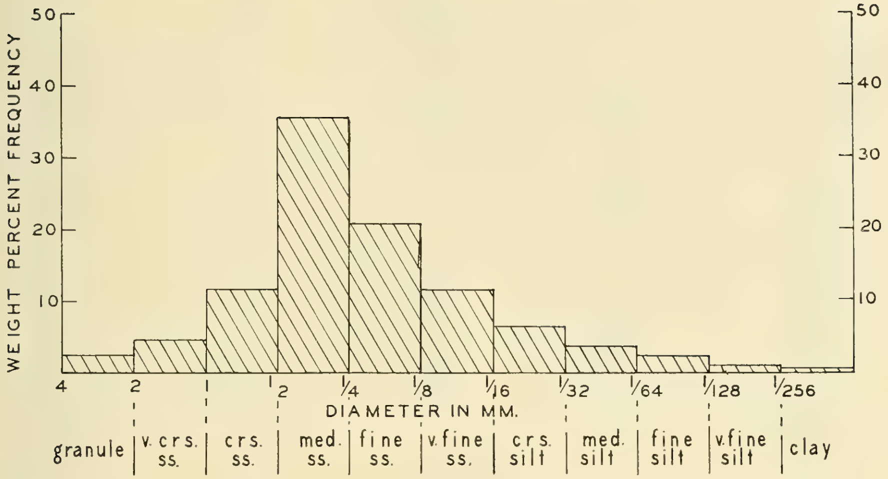


FIGURE 6-1. Histogram prepared from data in Table 6-2.

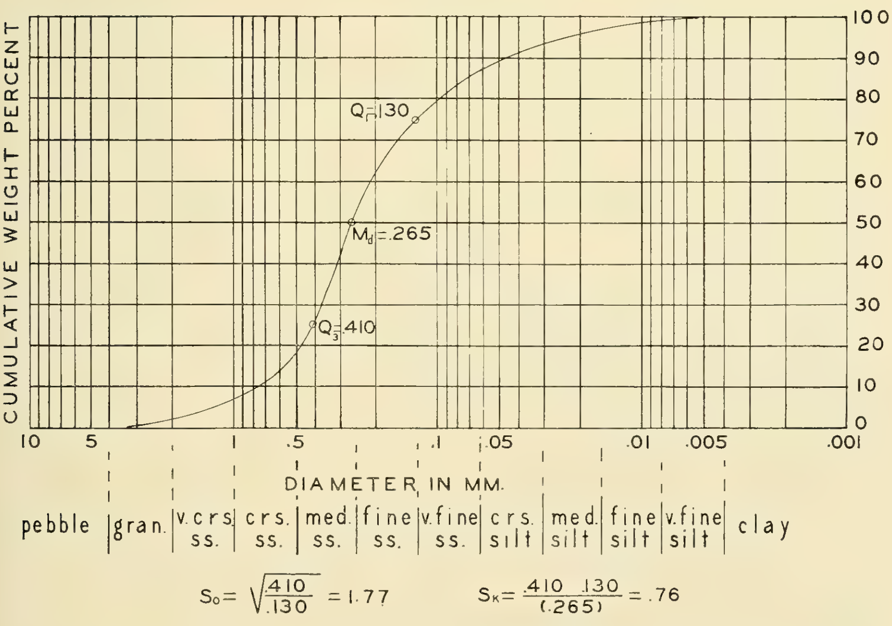
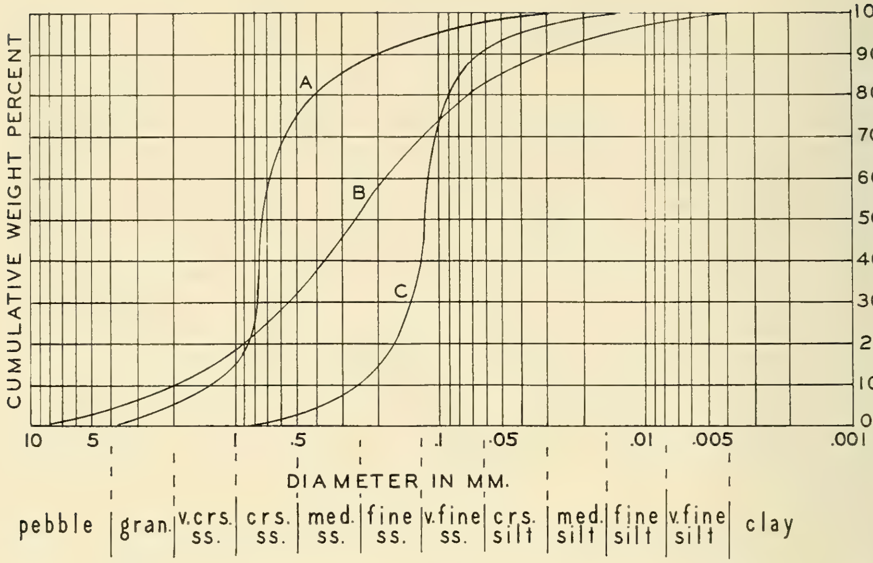


FIGURE 6-2. Cumulative-frequency curve prepared from data in Table 6-2.



A	B	C
M_d –.750	M_d –.265	M_d –.120
Q_1 –.500	Q_1 –.096	Q_1 –.100
Q_3 –.820	Q_3 –.700	Q_3 –.154
S_o –1.28	S_o – 2.70	S_o –1.24
S_k –.73	S_k –.96	S_k –1.07

FIGURE 6-3. Cumulative-frequency curves and statistical parameters of three different sands.

The histogram is the simplest type of diagram that shows graphically the results of a size analysis. Normally the size intervals are plotted along the horizontal axis and the weight percentage of each size interval along the vertical axis. Because the range of grain diameters is not equal for each size interval, a logarithmic scale is used along the horizontal axis; and if the Wentworth scale is used, each size interval will be equal width. Figure 6-1 is the histogram based on data recorded in Table 6-II.

The cumulative-frequency curve (fig. 6-2) is plotted on semi-logarithmic paper, with the logarithmic scale representing the diameter of the grains in millimeters and the arithmetic scale representing the cumulative-weight percentage. The cumulative-frequency curve is prepared by plotting opposite the diameter of each screen opening the weight percentage that would have been retained by the screen if all screens larger had not been used. Figure 6-2 is the cumulative-frequency curve plotted from the data in Table 6-II.

The cumulative-frequency curve emphasizes the continuous distribution of sizes and has the advantage that statistical data may be obtained directly from

TABLE 6-II

Size Analysis Data

Sample No. A-1 — Formation: XYZ

Date — Sept. 3, 1956

Mesh No.	Opening in mm	Grams Retained	Percent Retained	Cumulative Percent
5	3.962	0	0	0
7	2.794	0.9	1.0	1.0
9	1.981	1.4	1.5	2.5
12	1.397	1.8	1.9	4.4
16	.991	2.5	2.7	7.1
24	.701	3.7	3.9	11.0
32	.495	7.2	7.7	18.7
42	.351	14.4	15.3	34.0
60	.246	19.8	21.1	55.1
80	.175	11.5	12.2	67.3
115	.124	8.0	8.5	75.8
170	.088	6.0	6.4	82.2
250	.061	4.5	4.8	87.0
	.050	2.1	2.2	89.2
This portion of analysis run in Werner-type sedimentation tube	.040	1.8	1.9	91.1
	.030	2.2	2.3	93.4
	.020	2.3	2.4	95.8
	.010	2.3	2.4	98.2
	.004	1.4	1.5	99.7
	—.004	0.2	0.2	99.9
Total		94.0 gms	99.9 per.	

the curve. The most commonly used statistical values are the median (M_d), the first quartile, (Q_1), and the third quartile (Q_3). The median diameter (M_d) is the diameter at the intersection of the 50-percent line and the cumulative frequency curve. The first quartile (Q_1) is the diameter at the intersection of the 75-percent line and the curve and the third quartile (Q_3) at the intersection of the 25-percent line and the curve. From these values the sorting coefficient (S_o) and skewness (S_k) introduced by Trask (1930) are computed.

The sorting coefficient (S_o), a geometric quartile deviation, is computed by the equation $S_o = \sqrt{Q_3/Q_1}$. As Q_3 is always the larger value, the value of S_o will always be greater than 1.0. A sediment having a sorting coefficient equal to 1.0 would be perfectly sorted. The greater S_o becomes, the more poorly sorted the sediment. Trask proposed that sediments with an S_o less than 2.5 are well sorted, a value of 3.0 normally sorted, and values greater than 4.5 are poorly sorted. It should be noted that Trask's sorting coefficient applies only to the central 50 percent of the curve. The coarser and finer grades have little influence on the value.

The skewness (S_k), which is a measure of asymmetry of the frequency curve, is obtained by the formula, $S_k = \frac{Q_1 Q_3}{(M_d)^2}$. This value, which is in effect the square of the geometric quartile skewness, has the advantage that, if the value is less than unity, the maximum sorting or spread lies to the left or coarse side, and if greater than unity, the maximum sorting lies on the fine side. If S_k is equal to unity, the curve is symmetrical, and sorting is uniform on both sides of the frequency curve. Figure 6-3 shows the cumulative-frequency curves and the statistical parameters obtained from the curves of three different types of sands.

Interpretation of Data

Probably in no geologic procedure have statistical methods been used more than in the interpretation of size analyses. A review of recent literature indicates that modern sedimentary petrologists must have a working knowledge of statistical methods. There is, however, some difference of opinion as to the value of these statistical methods. Krumbein and Pettijohn (1938) state:

> The preceding sections on correlation, the X^2 test, the theory of control and the probable error indicate that there is a growing recognition of the importance of statistical analysis in sedimentary problems. One cannot ignore the contributions which such studies have made and will make to a fuller understanding of the complex study of sediments . . .

On the other hand, Twenhofel and Tyler (1941) comment:

> Statistical methods of study may ultimately be shown to have more value than is now apparent. Statistical results certainly permit rapid and easy comparison of large numbers of sediments and render it simple to point out similarities and differences. What significances the results have in terms of environmental conditions remain to be determined. So far as the writers' survey of the field is concerned, the best that may be stated is that the significances of the studies are not apparent. Statistical studies certainly permit extensive use of mathematical formulae which are of interest to those who are mathematically inclined. The writers have found these formulae of great interest, but not particularly useful so far as interpretation of the sediments are concerned.

Pettijohn (1949), in commenting on the various objectives of mechanical analyses says, "Greatest effort and greatest disappointment have centered about the last of these objectives (identification of agent or environment). The results to date have not been up to expectations."

Emery (1954), in discussing average median diameter, sorting coefficient, percent of $CaCO_3$ and percent of organic matter of sediments from various recent environments in Southern California, states:

> It must be emphasized that table I cannot be used as a reliable basis for determining the probable environment of deposition for a given sample. The table merely lists the average values of several parameters for different environments of southern California. In each environment there is considerable variation. Under different climate or source con-

ditions, either present or past, the parameters may well be different. Their true effectiveness for characterizing environments can de determined only after similar compilations have been made for other regions and all are compared.

Size analyses and the resulting statistical parameters alone cannot identify the agent or environment responsible for the origin of a sediment. However, there is little doubt that data obtained from size analyses will improve the classification and description of clastic sediments. This is especially true of the fine-grained sediments where many so-called very fine-grained sandstones are actually siltstones. Shepard's proposed system (1954) of nomenclature based upon the ratio of sand, silt, and clay demonstrates that more attention must be given to the finer clastic particles if a standard system of nomenclature for clastic rocks is to be established. Too often the particles below 1/16 millimeter are ignored because of the time-consuming procedures required in the analysis of these small particles. A rapid and easy method of determining relative percentages of silt-and-clay size particles in the so-called pan fraction is needed.

In summary, it may be stated that size analyses have a definite place in the study of clastic sediments. More attention needs to be given to the silt-and-clay size particles, especially in the classification of the sediments and in lithofacies studies. Statistical methods are useful in the study of size analyses, but we should guard against becoming so involved in statistics that we neglect the geological objectives of the anaylses.

HEAVY MINERALS

Minerals with a specific gravity greater than about 2.86 are termed heavy minerals. Most clastic sediments are composed of minerals having a specific gravity less than 2.86.

The less common heavy minerals must be separated from the bulk of the sediment before they can be studied. Various separating techniques have been used, but the most common and widely used techniques involve liquids having a specific gravity ranging from 2.8 to 2.96.

Some of the more common heavy minerals include tourmaline, zircon, garnet, staurolite, and various pyroxenes and amphiboles. Heavy-mineral studies aid in determining the source area or provenance of sediments and in some instances, are useful in correlation problems. The literature on heavy-mineral techniques and interpretations is voluminous, and those interested in the details of the subject are referred to the standard textbooks of Krumbein and Pettijohn (1938) and Twenhofel and Tyler (1941).

Equipment

Many specialized types of equipment have been designed for heavy-mineral separation procedures. The simplest and most practical setup, which is shown in Figure 6-4, consists of two glass funnels, a stand to support the funnels one above the other, a short rubber tube attached to the stem of the upper funnel, and a tubing pinch clamp. A heavy liquid, filter paper, several beakers, a large cover glass, a glass stirring rod, alcohol, and an alcohol wash bottle complete the essential equipment. Petrographic glass slides, cover glasses, hot plate, xylene, and mounting material (Canada balsam or Lakeside No. 70) are used to prepare the mineral grains for study.

Procedure

The sample must first be disaggregated to free the heavy-mineral grains. The author prefers to run a size analysis and then to separate the heavy minerals from various size fractions. The fine- or very fine-grained sand fractions, as well as the most abundant size fractions are used. The finer sized fractions are preferred because there is normally a higher percentage of heavy minerals in these fractions, and minerals of this size can be identified petrographically more easily. Larger grains often are difficult to examine under the microscope because they are too thick to transmit adequate light; therefore the optical properties are difficult to determine. The tendency of the silt-size particles to coagulate into small aggregates in the heavy liquid makes it difficult to separate the heavy minerals from the light fractions. The time required for small grains to settle through the heavy liquid increases the time necessary for separation. Centrifuging the silt-size particles will speed up the separating process.

If a size analysis is not desired, the sample first must be disaggregated as outlined under Size Analyses (see page 95). A more complete discussion of sample disaggregation is given by Krumbein and Pettijohn (1938). The use of acids and other chemicals should be minimized in the disaggregation processes because the less stable minerals may be corroded or destroyed. Sand grains often are coated with iron oxide, which must be removed before mineral identification. Leith (1950) discusses various reagents for removing this coating from mineral grains. An ultra-sonic cleaner has been used effectively to clean grains. Because no chemicals are used in this technique, there is little danger of destroying or modifying the mineral grains.

After the sample has been disaggregrated and the iron oxide eliminated, the sample is dried and passed through an 80- or 115-mesh screen to remove the coarse material. The silt and clay particles are removed by screening or decanting, and then the sample is dried and weighed. For most sands a 20- to 50-gram sample is sufficient; however, if the percentage of heavy minerals is excessively low, it may be necessary to use a larger sample and to concentrate it

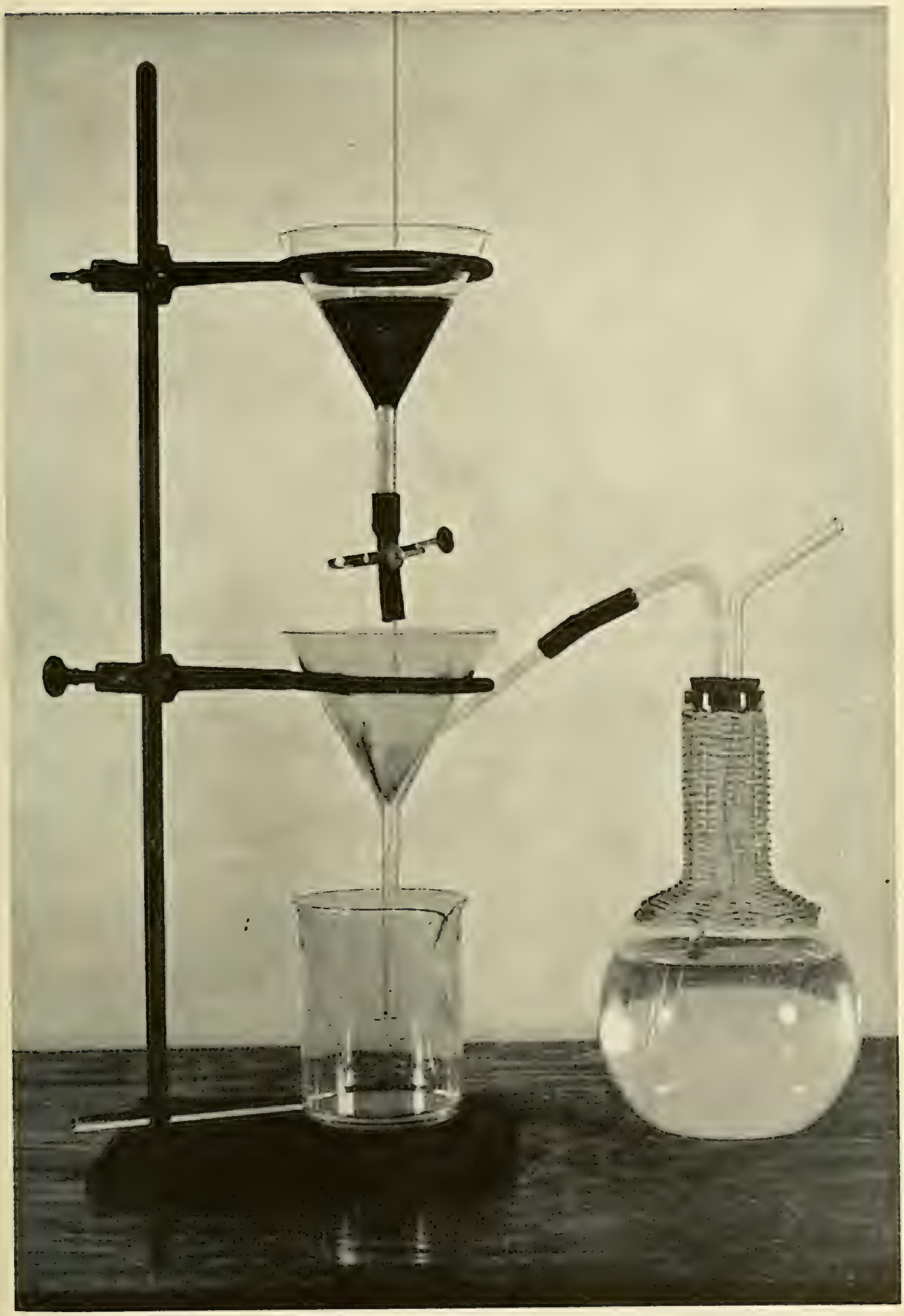


FIGURE 6-4. Arrangement of funnels for heavy-mineral separation.

by panning before the separation is made. In general, the older the geologic age of the rock, the fewer the heavy minerals.

The funnels are set up as shown in Figure 6-4. The pinch clamp on the upper funnel is closed and the funnel filled about two thirds full of a heavy liquid. The most commonly used heavy liquids are bromoform (sp. gr. 2.86) and acetylene tetrabromide (sp. gr. 2.96). Both are soluble in alcohol, colorless when fresh, nonpoisonous, and essentially chemically inert. The fumes of both are not unduly disagreeable but are sufficiently toxic to require adequate ventilation. A large cover glass placed over the funnel containing the heavy liquid minimizes evaporation. The writer prefers acetylene tetrabromide because a cleaner mineral separation generally is obtained; however, the odor is slightly more objectionable than that of bromoform, and acetylene tetrabromide passes through filter paper more slowly.

The sample is placed in the heavy liquid in the upper funnel and stirred gently. Minerals having a specific gravity greater than that of the liquid will sink and be retained by the pinch clamp. The heavy minerals may adhere to the side of the funnel just above the stem, but they can be dislodged by gentle stirring with a glass rod. When the heavies have settled, a filter paper is placed in the lower funnel, the pinch clamp is opened momentarily, and the minerals are flushed on the filter paper. If the sample contains many heavy minerals, it may be necessary to repeat the operation two or three times to prevent clogging of the funnel stem and rubber tube. After the heavy liquid containing the minerals is allowed to filter off, the filter paper is removed to another funnel, and the minerals are washed with alcohol. The heavy minerals are allowed to dry and then are transferred to a small glass vial. Another filter paper is then placed in the lower funnel, the pinch clamp is opened, and the heavy liquid and the remaining light minerals are drained off. The liquid is saved and can be reused. The light minerals are washed with alcohol, dried, and filed for further study.

The alcohol washings are placed in a collecting jar, and the bromoform or acetylene tetrabromide is reclaimed by water washing. When the jar is about half full of alcohol washings, an equal volume of water is added, and the jar is shaken vigorously. Alcohol, being soluble in water, is separated from the heavy liquid, which settles to the bottom. The alcohol-water solution is decanted off, and the process is repeated three or four times in order to remove excess alcohol. After the final decantation, the heavy liquid and remaining water are placed in a separatory funnel. The heavy liquid is drawn off and passed through several filter papers, which absorb included water and remove other suspended solid matter. The liquid may then be reused, but it should first be tested either by a hydrometer such as described by Tester (1931) or by a mineral of known specific gravity (quartz, calcite, dolomite, anhydrite). Commercial bromoform is often diluted with alcohol and should be tested before using. If the specific gravity is low, it should be washed with water in the same manner as described above.

A rapid and simple method of heavy-mineral separation is described by Wagner and Gableman (1950) and Feo-Codecido (1956). This method involves placing the heavy liquid in an evaporating dish, adding the sample, and stirring. The heavy minerals collect at the bottom of the dish and the light minerals float on the surface. The light minerals then are spooned or decanted off, and the heavy minerals are recovered from the bottom, washed, and dried. Although this method is fast, one must be careful to avoid mixing the heavy and light fractions.

The heavy minerals are usually mounted on glass slides for study. Before the grains are mounted, magnetite is magnetically removed. The slide should contain a representative sample of the mineral grains, and if the sample is too large, it must be split. A micro-split such as described by Otto (1933) is preferred, but if this equipment is not available, the sample may be placed on a paper, coned, and divided into quarters. Alternate quarters are then combined. The process may be repeated until the desired sample size (approximately 1000 grains) is obtained.

Either Canada balsam or Lakeside No. 70 cement may be used in preparing the slide. The writer prefers the cement because it is less difficult to handle. The slide is warmed on a hot plate until the applied cement melts. The melt is stirred with a needle to remove air bubbles. The minerals are sprinkled into the melt, and a cover glass is placed over the minerals. The slide is then removed from the hot plate and the cover glass is pressed down lightly to remove air bubbles and the cement is allowed to cool. Excess cement can be removed by gentle scraping with a knife blade and washing with xylene. After the slide is labeled, preferably by a diamond pencil on the glass, it is ready for examination.

Mineral Identification

The mounted minerals are studied with an ordinary petrographic microscope. Optical characteristics, cleavage, shape, color, corrosion, and inclusions are the properties evaluated during routine identification. Several references on heavy-mineral identification are recommended, among which are Milner's textbook (1940), Russell's tables (1940-41), Larsen and Burmen (1934), and a section in Krumbein and Pettijohn (1938). The author has found Milner's descriptions and illustrations very helpful, and the arrangement of Russell's tables is very convenient.

After the minerals have been identified, an estimate of their relative frequency is determined. When a large number of samples must be examined rapidly, as in commercial work, a visual estimation of the relative abundance is made. Feo-Codecido (1956) describes the procedure used by an oil company in Venezuela, in which visual estimation is made, and each mineral is assigned a frequency number based upon its relative abundance, as shown below.

Frequency Number	*Descriptive Term*
5	Flood
4	Abundant
3	Common
2	Fairly common
1	Rare
0	Very rare

These numbers are only symbols, not true numbers in a mathematical sense.

When time is available and an accurate grain count is made, a mechanical stage is attached to the microscope so that spaced traverses may be made across the slide. Dryden (1931) has pointed out that it is not profitable to count all grains, as the law of diminishing returns is involved. The increased accuracy obtained after counting approximately 300 grains does not justify additional counting. Percentages should be calculated to the nearest whole number.

After the relative mineral frequencies have been determined, the data usually are presented in graphical form. Histograms, bar diagrams, profile charts, star diagrams, and tables of various types have been used. Krumbein and Pettijohn (1938) and Feo-Codecido (1956) give examples of such tabulations and diagrams.

Interpretation of Data

Interpretation of heavy-mineral data has received much attention by sedimentary petrologists, and differences of opinion naturally exist. Heavy-mineral studies have been used principally in determining the source rocks or provenance of sediments and in correlating and identifying stratigraphic units.

Pettijohn (1957) gives an excellent review and discussion of source provenance and the effects of transportation or dispersal of detrital minerals. One of the problems of heavy-mineral studies is the variation of complexity of mineral suites with the geologic age of the sediment. The older Paleozoic rocks usually contain a simple suite of the more resistant minerals such as zircon, tourmaline, rutile, staurolite, and garnet. Younger rocks, particularly the Recent deposits, usually contain more diversified mineral species. In addition to the more resistant minerals listed above, the younger rocks often contain pyroxenes, amphiboles, and other less resistant minerals such as epidote, kyanite, and sphene. Pettijohn (1941) believes that in the older rocks the less resistant minerals have been removed by intrastratal solution, whereas, Krynine (1946) believes that the variation in mineral suites are due principally to differences in source rock. When one is working with the restricted mineral suites of the older rocks, it is important that the varieties of each mineral be recorded because these subspecies may yield more information than the total suite. Krynine (1946) demonstrates the stratigraphic use of the varietal properties of tourmaline. He recognizes many subspecies of this mineral and suggests 5 different source areas based upon these variants. Detailed studies of other resistant minerals may lead to similar results.

The use of heavy minerals in correlating and identifying stratigraphic units is described by Feo-Codecido (1956). In areas where paleontological data are sparse or non-diagnostic, heavy-mineral studies may aid greatly in correlations, as has been proved in Venezuela. It is general practice to define suites of minerals for various stratigraphic units much as fossil assemblages are established. Zones may be erected on the basis of mineral suites, relative abundance or ratio of mineral species, and depositional sequence relationships.

Heavy-mineral studies must be based on systematic sampling which is necessary to establish the stratigraphic relationships. Conclusions based upon the study of only a few scattered samples may be seriously in error. The petrographer must analyze and evaluate in terms of thousands of concentrates—not just a few hundred.

STAIN METHODS

Staining methods are used to distinguish calcite from dolomite, calcite from aragonite, and quartz from feldspars. These methods have also proved helpful in identifying certain clay minerals. The principal use of staining procedures is to evaluate the textures and mineral distribution in a rock; however since these methods are not precise, petrographic, X-ray, and chemical analyses should be made if more exact mineralogic determinations are desired.

Stain tests may be made on polished slabs, thin sections, or grain aggregates. If textural relations are desired, a polished slab is preferred. Uniformity in strength of solutions and immersion time is necessary for consistent and reliable results.

Calcite and Dolomite

Several methods may be used to distinguish calcite from dolomite. The most widely used are the Fairbanks' (1925) method; the copper nitrate method, first suggested by Mahler (1906); and the silver chromate method developed by Lemberg (1892). Rodgers (1940) gives a thorough review of staining methods as applied to calcite and dolomite.

Fairbanks Method

This method is a modification of one described by Lemberg (1887). The stain solution is prepared by mixing 0.24 grams of haematoxylin, 1.6 grams of aluminum chloride, and 24 cubic centimeters of water. The mixture is brought to a boil and cooled; then a small quantity of hydrogen peroxide is added. The solution is then filtered and ready for use. Calcite will stain a dark purple when immersed about 30 seconds in the solution, whereas dolomite remains unaffected. Osborne (Australasian Petroleum Company) suggests doubling the amount of haematoxylin and immersing the specimen for 5 to 10 minutes. He also states that upon occasion the stain may be improved by holding the specimen over an open bottle of strong ammonia. The Fairbanks method is reliable and fast because it is not necessary to boil the specimen in the solution.

Copper Nitrate Method

When boiled in a solution of copper nitrate, calcite is stained green, whereas dolomite is unaffected. Ross (1935) suggests that the specimen be immersed in a cold solution of copper nitrate for several hours. Rodgers (1940) recommends a one-molar solution of copper nitrate and immersion for 5 hours at room temperature. The color is fixed by immersing in ammonia. This test gives good and consistent results.

Silver Chromate Method

In this method the specimen first is immersed 3 or 4 minutes in a hot (70C) 10-percent solution of silver nitrate, washed, and then placed in a saturated solution of potassium chromate for about 1 minute. Calcite is stained reddish-brown, whereas dolomite is unaffected. Weaker solutions of silver nitrate and potassium chromate give a more delicate and selective test. Osborne suggests that a 1-percent solution of silver nitrate and a 2-percent solution of potassium chromate be used. He also recommends that the sample be treated 1 minute in a cold instead of a hot silver nitrate solution.

Calcite and Aragonite

A method of distinguishing aragonite from calcite was suggested by Meigen (1901). The specimen is immersed for 20 minutes in a solution of boiling cobalt nitrate. Aragonite stains a light purple in the initial stages and becomes dark purple upon continued treatment. Calcite stains a similar color only after several hours of immersion.

Quartz and Feldspars

It is often desirable to determine the percentages of quartz and feldspar in a sediment, and it is usually time consuming to distinguish between the two by petrographic procedure. A simple and reliable staining method first suggested by Becke (1889) can be used effectively to distinguish between these two minerals. Twenhofel and Tyler (1941) summarized this method as follows:

> A few drops of hydrofluoric acid are placed on a thin section, or on grains mounted in Canada balsam with their upper surfaces exposed, and allowed to remain for 1 or 2 minutes before being gently washed off. The acid produces a thin, gelatinous film of aluminum fluorosilicate on the feldspar and other aluminous minerals, but leaves the quartz clear. After washing, the specimen is immersed in a water soluble organic dye for about five minutes and then again washed. Fuchsine, methylene blue, safranine, or malachite green may be used as a stain . . . The degree of gelatinization, and therefore the depth of color retained on staining, is greatest with anorthite; becomes successively lighter with less calcic feldspars; and is lightest with orthoclase or microcline.

Clay Minerals

Staining methods can be used effectively in clay mineralogy. Mielenze, King, and Schieltz (1951) discuss the procedures and results of many tests.

Care should be taken in applying stain solutions to clay minerals because impurities, improper or inconsistent procedure, and the complex nature of the clay minerals may cause extremely variable results. Staining methods are used principally as aids in petrographic analysis. They are also very useful in routine examination of suites of samples when representative samples have been X-rayed.

Certain impurities affect many of the stain tests. For example, ferrous iron and other reducing agents may prevent a color change, whereas manganese oxide will give a blue color with benzidine even if clay minerals are absent. On the other hand, quartz, feldspar, carbonates, gypsum, muscovite, biotite, sericite, chlorite, iron oxides, glauconite, volcanic glass, and other nonclay minerals do not affect the tests.

The sample (about 20 grams) should first be pulverized, then divided into two equal parts by quartering. To one portion hydrochloric acid is added and heated to about 50C for 2 hours. It is then washed thoroughly with distilled water. The washing is continued until silver chloride fails to form when silver nitrate is added to the wash water. The sample is then dried in an oven at 105C for about 24 hours. A small portion (about 1 milligram) of the dried sample is then placed on a glass slide; and after staining, one evaluates the resulting color by comparing it with a standard color chart. Comparisons are made with petrographic microscope equipped with a comparator eyepiece.

Tests are run on both the untreated and the acid treated portions of the sample. The portion of the sample treated with hydrochloric acid is tested with a nitrobenzene, solution of safranine "y" and malachite-green. The portion not acid treated is tested with an aqueous solution of benzidine. Three or four drops of the solution are added to the material on the glass slide and stirred to wet the material. In the benzidine test, one should wait about 5 minutes before examining. If no stain reaction is noted, a periodic examination should be made up to about 2 hours for any characteristic color change. In the safranine "y" and malachite-green tests, the sample should be examined between 2 and 10 minutes after the dye has been added. After about 10 minutes, the stained particles may darken and become opaque, making the interpretation difficult.

The characteristic results of these staining tests are summarized in Table 6-III, prepared by Mielenze, King, and Schieltz (1951). These tests are quite sensitive, and it is recommended that trial tests be made on samples accurately identified by X-ray diffraction.

TABLE 6-III

Characteristic Staining of Clay Minerals
(Mielenze, King, and Schieltz, 1951)

Clay mineral	Untreated clay	Acid-treated clay	
	Benzidine	Safranine "y"	Malachite-Green
Kaolinite	No reaction	Red-Purple red* Strong to weak pleochroism from reddish-purple parallel to cleavage to yellowish-red perpendicular to cleavage	Blue-Green Blue and Blue-Green* Strong to weak pleochroism from yellowish-green parallel to cleavage to blue perpendicular to cleavage
Halloysite	No reaction	Blotchy stain - Purple, Purple-Blue Purple and Red-Purple Red. Not pleochroic	Blotchy stain - Yellow Green-Yellow, Blue-Green, and Green-Yellow, not pleochroic
Dickite	No reaction	Crystals not stained. Very weak pleochroism from reddish-purple or purple parallel to cleavage to reddish-yellow perpendicular to cleavage	Crystals not stained. Very weak pleochroism from yellowish-green or colorless parallel to cleavage to light blue perpendicular to cleavage
Nacrite	No reaction	Crystals not stained. Weak pleochroism from reddish-purple parallel to cleavage to yellowish-red perpendicular to cleavage	Crystals not stained. Weak pleochroism from yellowish-green parallel to cleavage to blue perpendicular to cleavage
Montmorillonite**	Purple-Blue	Purple-Blue	Yellow-Red Yellow
Nontronite	Blue-Green	Red-Purple Red*	Green Blue-Green and Blue-Green Blue*
Hectorite	Purple-Blue	Red-Purple Red*	Blue-Green Blue*
Illite	No reaction	Red-Purple Red*	Green Blue-Green*
Attapulgite	No reaction	Red-Purple Red*	Blue-Green and Blue-Green Blue*
Pyrophyllite	No reaction	Not stained	Not stained

*Dye absorbed without change in color. Samples of nontronite included with the clay mineral standards did not change the color of the dyes in these tests, but specimens of nontronite reacting in a manner similar to montmorillonite, have been examined in the petrographic laboratory.

**No beidellite is included in the clay mineral standards; beidellites examined in the petrographic laboratory typically react in the staining tests, as does montmorillonite.

ETCH METHODS

Acid etching is a simple and rapid method applicable to the study of the texture; grain size; ratio of calcite to dolomite; and the type, distribution, and approximate amount of insoluble material or fossil content of limestones and dolomites. Acid etching does not replace, but only supplements, thin-section and insoluble-residue studies. Etching often reveals impurities and three-dimensional grain relationships. The distribution of insoluble materials and their relationship to bedding also are brought out clearly by etching.

Very little has been published on acid etch tests. Probably the most complete discussions are given by Lamar (1950) and Ives (1955).

The necessary equipment for etch tests are a rock saw, polishing abrasive, flat-bottomed glass dishes or beakers, acid (hydrochloric and acetic), and a binocular microscope. The size of the sample used depends upon the material available and the information desired. Ives (1955) used slabs about 6 inches long, 1⅝ inches wide, and approximately ½ inch thick. The author has used slabs about 2 inches square and ¼ to ½ inch thick. Larger or smaller pieces may be used, but at least one side should be flat and polished. The specimen is placed in a flat-bottomed dish with the polished side up. The polished surface is leveled up on a water surface and held in place with modeling clay if necessary. Inclined surface may be channeled by rising streams of bubbles, and this channeling may be confused with significant etching results.

The most commonly used acids are dilute hydrochloric and acetic. Lamar (1950) recommends 23 cubic centimeters of C.P. glacial acetic acid in 100 cubic centimeters of water or 8 cubic centimeters of concentrated hydrochloric acid in 100 cubic centimeters of water. He also recommends etching for 20 minutes in acetic acid and 5 minutes in hydrochloric. It is essential that the acid reaction be slow; otherwise, the delicate features etched out may be destroyed. Since limestones and dolomites may differ in their acid reaction, the author recommends covering the specimen with about a half inch of water and then adding sufficient acid to start mild effervescence. After the polished surface has been thoroughly etched, the specimen is removed from the acid and gently washed. It is best to immerse the specimen two or three times in a beaker of water instead of washing it under a faucet as there is less danger of destroying the features brought out by the etching.

Acetic acid is less uniform in its etching action and usually produces a rough surface. Hydrochloric acid usually produces a smoother surface and often gives a polished appearance to the surface. In general both acids should be tested because it is sometimes difficult to predict which one gives the best results. Figures 6-5, 6-6, 6-7, and 6-8 are photographs of etched surfaces prepared by Lamar (1950).

FIGURE 6-5. Paint Creek limestone near New Hanover, Illinois. Hydrochloric acid etch. Sand grains and masses of fine-grained silica project above ground mass of mostly clear, relatively coarsely crystalline calcite which photographs black or dark gray. X18 (Lamar)

FIGURE 6-6. Paint Creek limestone near New Hanover, Illinois. Acetic acid etch. Sand grains less clearly visible than in Figure 6-5. Local differential deepening of some areas of clear calcite; a few scattered oolite grains present. X18 (Lamar)

FIGURE 6-7. Salem limestone, St. Genevieve, Missouri. Hydrochloric acid etch. Surface essentially plane; a clastic rock composed of oolite grains and fossil detrites; dark areas are clear calcite; large fragment of crinoid stem in center of specimen; a few small grains and masses of silica project above ground mass. X18 (Lamar)

FIGURE 6-8. Salem limestone, St. Genevieve, Missouri. Acetic acid etch. Surface rough; notable differential etching; clastic character of limestone well shown; fossil fragments project notably above ground mass; crinoid stem fragments at bottom of specimen show differential solution; in upper center is a spine, possibly of an echinoid; presence of impurities not well shown. X18 (Lamar)

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Chapter 7

DIFFERENTIAL-THERMAL ANALYSIS

George B. Mangold

A major source of information on subsurface geology during the drilling of an oil well is the cuttings. Each successive stratum is represented; the samples are obtained without extra cost; and represent an actual part of the penetrated formation.

Failure to make full use of the cuttings has been due to (1) the belief that the samples are always contaminated, (2) the belief that depth identification and stratigraphic position are inaccurate, and (3) the lack of an inexpensive method of providing a meaningful mineralogical analysis of the cuttings. With the advent of drilling-mud control and careful formation logging, and through the use of differential-thermal analysis, these objections, for the most part, are no longer valid. If the drilling fluid is properly maintained, sloughing of the hole is virtually eliminated, and contamination of cuttings from other depths becomes insignificant. Through continuous regular determination of lag time, depths can be assigned to the cuttings with an accuracy almost comparable to that of cores.

Many methods have been used for analyzing cuttings. The simplest, of course, is examination through a binocular microscope. A competent geologist can make detailed descriptions of the cuttings at regular depth intervals; however, the results are dependent largely upon the human element.

Thin-section analysis, X-ray analysis, and chemical analysis provide different types of information, each of which lends itself to correlation; however, these techniques are time consuming and expensive. They are excellent research tools but commonly play a minor role in competitive exploratory and production drilling. Paleontological analysis has been successful in many areas, but again the method is too expensive for small operators and can be applied only if microfaunas are present. Clay-swelling analyses are useful but are definitely limited for correlative purposes. Radiation analysis is a new and inexpensive method that holds considerable promise as an aid in correlation problems, but it seldom can be considered sufficient in itself.

At the present time differential-thermal analysis (DTA) approaches the practical solution to the problem of analyzing cuttings to give a maximum amount of information on mineral composition at a minimum cost. DTA provides a means of determining—by machine—compound and mineral composition, qualitatively and semi-quantitatively, with automatic recording of the results in the form of a differential-thermal curve. These curves, when determined for regular periodic depths of cuttings and prepared in log form, provide an excellent basis for correlating drilled sections. Results, which are a direct mineralogical picture of formation material, are not altered by the physical characteristics of the zone, the fluids present, and the temperature and pressure environment, as are results obtained by in-the-hole logging methods. Results from DTA can be obtained within a short time after drilling, or they can be delayed for years until the need arises, provided the cuttings have been cleaned and stored properly.

As early as 1947 the need for subsurface correlation by DTA was recognized and propounded by Florent H. Bailly (1952), who initiated and developed its use on a volume basis in the exploration for oil. Many previous investigators (Berkelhamer, 1944; Grim and Rowland, 1942 and 1944; Norton, 1939; Speil, Berkelhamer, Pask, and Davies, 1945), have shown the value of DTA for the identification and study of clays, aluminous minerals, and hydrous materials, but it remained for Bailly to adapt the method to the production of logs with the specific goal of achieving correlation of subsurface formations. Techniques have been improved greatly and speed of determination increased many fold. Thousands of samples have been tested and DTA logs prepared for numerous wells and the correlation results have been most encouraging.

DEFINITION OF DIFFERENTIAL-THERMAL ANALYSIS

DTA is a measurement of the physical and chemical reactions induced in a substance or mineral assemblage by change in temperature at either constant or variable pressure, a measurement in terms of the gain or loss of heat energy. These reactions include changes of state such as melting and evaporation, loss of water of hydration and crystallization, decomposition, oxidation, alterations of crystal structure, and development of new compounds. Each reaction which involves a definite amount of heat energy, will take place at a definite temperature that depends upon the type of compounds involved and the pressure of the particular gaseous environment, thus providing the means of identification.

THERMOCHEMISTRY

We shall consider a small insulated container full of ice in which a sensitive thermometer is embedded. Initially the temperature will be somewhat below 0C. If heat is applied at a uniform rate, the temperature will rise to 0C, at which time melting will commence. As heat is applied continuously, the temperature will remain at 0C until melting is completed. Only then will the temperature of the resulting water start to rise. A reaction has taken place due to the application of heat—a physical change of state involving the absorption of energy.

According to the first law of thermodynamics (conservation of energy), energy can be neither created nor destroyed, but only changed from one form to another. Thus, the liquid water in the preceding experiment absorbed heat energy by melting. During absorption there was no rise in temperature. Until the water cooled to the freezing point, it retained this energy. However, if heat is removed at 0C, the water would again freeze, thus returning the energy absorbed during melting. This, then, is an example of a reversible reaction induced by temperature change. The temperature of the reaction and the amount of energy involved is characteristic of the compound H_2O and can serve to identify it.

We shall consider another slightly more complicated example. Sulfur is placed in a closed insulated container with an inert gas such as nitrogen. A thermocouple is embedded in the sulfur, and leads are brought out to a pyrometer (millivoltmeter calibrated to read directly in temperature). If heat is applied to the container at a uniform rate, temperature as indicated by the pyrometer will rise steadily. This fact is represented in the plot of temperature vs. time, Figure 7-1A, as the line AB. When the melting point is reached, temperature will remain constant, line BC, until melting is complete. The temperature, CD, of molten sulfur then will rise to the boiling point. Evaporation takes place between D and E, again appearing as a horizontal line. The temperature, EF, of sulfur vapor then will rise. If at point F, air or oxygen is added to the container, the sulfur will oxidize immediately; heat from the reaction will cause a steeper temperature rise, FG. The reactions indicated by BC and DE are endothermic, meaning that they represent absorption of heat. The reaction FG is exothermic, meaning that it gives off heat.

THEORY OF DIFFERENTIAL-THERMAL ANALYSIS

The sulfur example just cited may illustrate also the difference between an ordinary heating curve (fig. 7-1A) and a differential-thermal curve (fig. 7-1B). Differences in equipment simply involve inclusion of additional material—thermally inert alumina (Al_2O_3)—in the furnace, and the use of a *differential* thermocouple. The latter is made from two identical thermocouples connected by one like wire of each. One thermocouple junction is embedded in the sample (sulfur), the other in the inert standard (alumina). The remaining wires then are connected to the pyrometer. As long as the two junctions are at the same temperature, induced voltage from each will cancel the other; but if the junction in the sulfur becomes hotter or colder than that in the alumina, the voltage induced in the appropriate direction indicates the *difference* of temperature between them. A separate regular thermocouple is used to measure the actual temperature of the alumina.

While steady heating takes place, as in the previous example, readings are made of alumina temperature and of differential temperature. The former is plotted vertically and the latter horizontally on either side of a zero position (fig. 7-1B). In this way, only a vertical line will result as long as the two materials are rising in temperature at the same rate. However, if the sulfur lags behind the alumina during melting, a curve or peak will be traced to the right of the

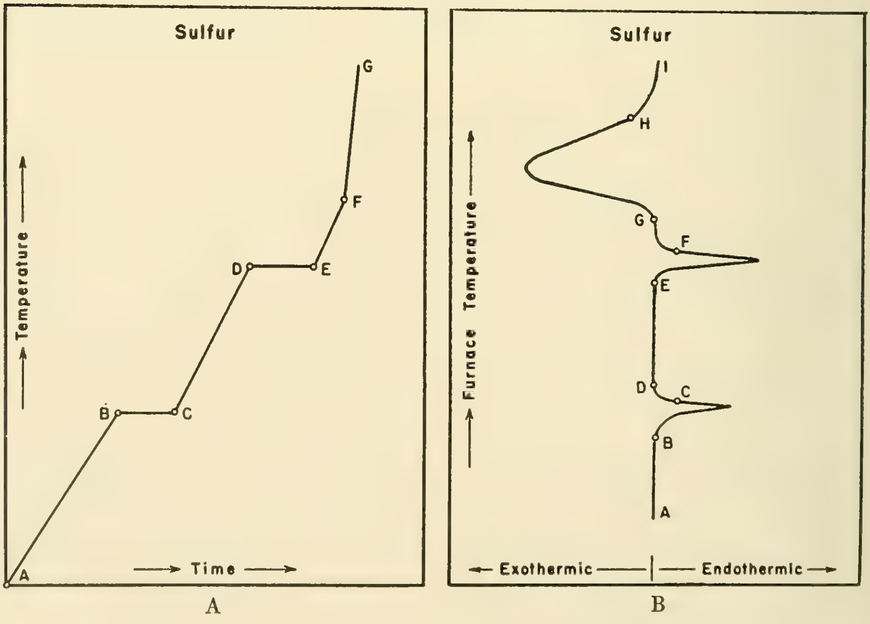


FIGURE 7-1. *A*—Heating curve. *B*—Differential-thermal curve.

vertical base line in an endothermic direction. An exothermic reaction will appear as a deviation to the left of the base line.

Thus, Figure 7-1B shows the heating curve of sulfur but in the form of a differential-thermal curve. The peak BCD represents melting; EFG, evaporation; and GHI, oxidation. The temperature of a peak is not the temperature at which the reaction commences, it is the temperature at which the greatest differential exists between the sample and the alumina standard. Also, the reaction is complete before the curve has come back fully to the base line, i.e., points C, F, or H. The area within each peak is a function of the type and concentration of element or compound causing the reaction. Observance of the temperature, shape, and size of the peaks provides a means of qualitative and semiquantitative analysis. More complete theory and mathematical relationships of differential-thermal analysis may be found in existing authoritative publications (Spiel, Berkelhamer, Pask, and Davies, 1945; Kerr, Kulp, and Hamilton, 1949).

It is not within the scope of this discussion to explain the effects of varying the kind of gas surrounding the sample or of varying the pressure of this gas. Research is progressing continuously on these more complicated phenomena and results appear periodically in the literature (Rowland and Lewis, 1951; Stone, 1954; Stone and Rowland, 1955). However, inasmuch as these specialized refinements of thermal-analysis technique are still largely of a research nature, it will suffice for this presentation to consider only the methods and results obtained under ordinary conditions of atmospheric-pressure and air environment.

QUALITATIVE ANALYSIS Typical DTA curves of several common minerals are shown in Figure 7-2. A brief explanation of each curve will aid in illustrating the type of results that may be obtained from thermal analysis. Curve A, representing alumina (Al_2O_3), is a straight vertical line, indicating that no thermal reactions occur within the temperature range covered (room temperature to 1000C). Curve B, quartz (SiO_2), shows one small sharp endothermic reaction at 573C, representing the crystal inversion from α to β quartz. Calcite ($CaCO_3$), curve C, is thermally inert up about 800C but the large endothermic reaction at about 925C represents the decomposition of the carbonate and the expulsion of carbon dioxide. Curve D, dolomite ($MgCO_3$ $CaCO_3$), shows two endothermic peaks at about 780 and 925C respectively, which represent the successive decompositions of magnesium carbonate and then calcium carbonate with the consequent loss of carbon dioxide.

Curve E, siderite ($FeCO_3$), shows the decomposition at 550C with loss of carbon dioxide. The remaining iron oxide (FeO) immediately oxidizes to Fe_3O_4, as indicated by the sharp exothermic peak at 600C. The small exothermic bulge centered at about 750C represents the further oxidation to hematite (Fe_2O_3).

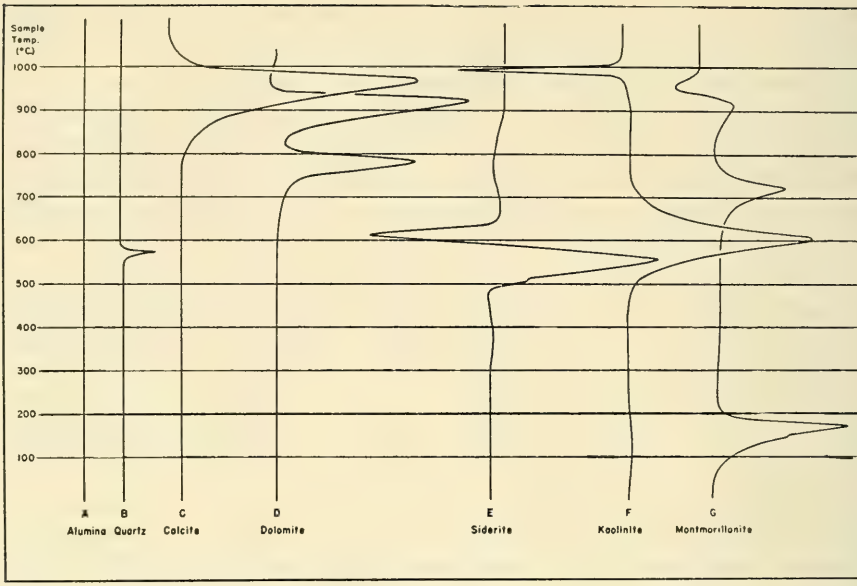


FIGURE 7-2. Differential-thermal curves of various minerals.

Curve F, kaolinite ($H_4Al_2Si_2O_9$), shows a strong endothermic reaction at 600C, representing destruction of the crystal lattice. At about 990C there is a sharp exothermic reaction due to recrystallization of amorphous alumina produced in the lattice breakdown. Curve G, montmorillonite (Wyoming type)—((Mg,Ca)O-$Al_2O_35SiO_2 \cdot nH_2O$?), exhibits several well-defined peaks. The lower endothermic peak at about 160C represents the loss of water of hydration (not to be confused with moisture, which may be absorbed on the surface of any mineral and which would appear as an endothermic bulge at about 100C. The large endothermic peak at about 700C and the smaller one at about 900C are due to the stepwise destruction of the lattice structure. After the final breakdown, crystallization of spinel ($MgAl_2O_4$) results in the exothermic peak which follows immediately (about 950C).

SEMIQUANTITATIVE ANALYSIS

When a mineral is present in less than 100 percent concentration, DTA peaks become correspondingly smaller and peak temperature is generally reduced. This fact is illustrated in Figure 7-3. The three curves at the left portray 25, 50, and 100 percent calcite, with inert alumina as the diluent. Although decomposition starts at the same temperature, the peak is reached sooner (at a lower temperature) with lower concentrations. This is brought

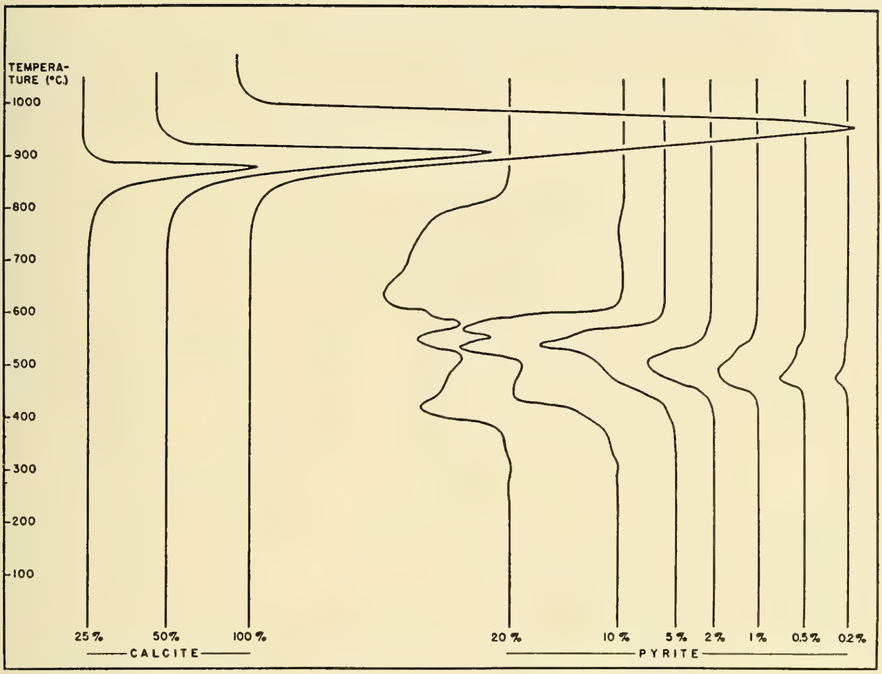


FIGURE 7-3. Effects of mineral concentration on differential-thermal curves.

about by the lower partial pressure of expelled carbon dioxide as well as by the lesser reaction time involved. Similarly, the pyrite curves at the right indicate the effects of concentration. In this instance the greater complexity of reactions and the presence and movement of sulfur dioxide gas produce more complicated curves. The sensitivity of DTA in detecting certain minerals is illustrated by the curve for 0.2 percent pyrite.

If the diluent is not thermally inert, i.e., ordinary mixtures of minerals as in rocks, soils, oil-well cuttings, etc., the same dilution effect will appear for each of the thermally active minerals present, and each will appear in proportion to its concentration in the sample. Figure 7-4 illustrates DTA curves for such a mineral assemblage and for selected fractions thereof. A complete oil-well ditch-cutting sample is represented by curve D. Portions of the same original sample were separated according to color, and DTA was determined on each. Curve A represents white and clear crystals making up about 20 percent of the total. The small endothermic peak shows quartz; the higher temperature peak shows halite (NaCl). Curve B resulted from DTA of a dark grey fraction comprising about 40 percent of the total. It shows clay and shale, organic matter, and considerable pyrite. The remaining 40 percent, a light grey fraction, yielded curve

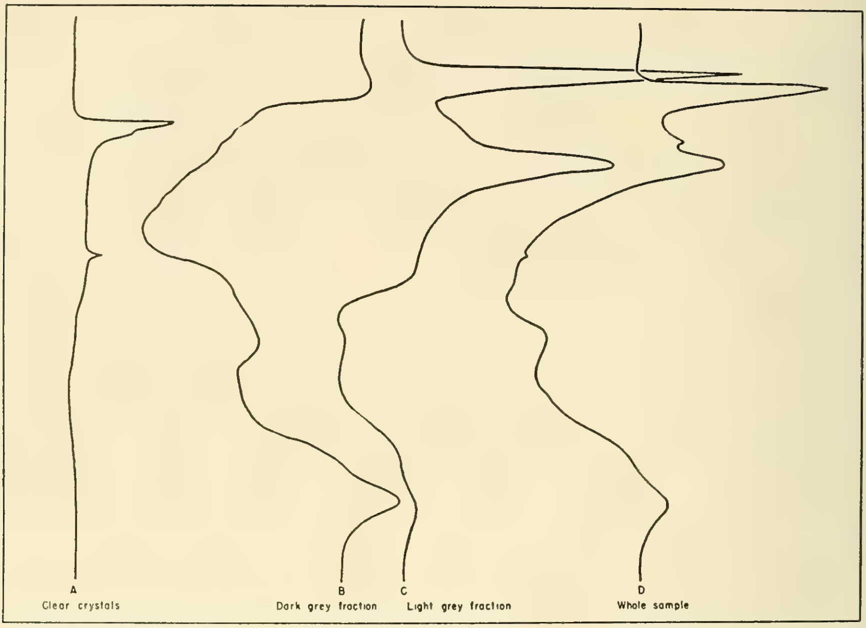


FIGURE 7-4. Compounding a differential-thermal curve. Data obtained from ditch cuttings.

C, showing largely dolomite, plus small amounts of minerals present in B. Curve D, the complete sample, shows each of the various separated minerals, each reduced in intensity according to its concentration, and with consequent reduction in peak temperature. The temperature of certain almost instantaneous reactions not affected by small changes in atmospheric pressure, i.e., the quartz inversion, will not be altered appreciably because of concentration and will remain essentially constant unless a simultaneous reaction is heating or cooling the sample at this point.

SUBSURFACE DTA CORRELATION

As mineral assemblages become more and more complex, it becomes increasingly difficult to analyze the minor compounds present. Nevertheless, the complex profile of the DTA curve is an accurate reflection of all thermally active minerals present and can be used for identification of or comparison with other mineral assemblages. This is the basis for correlating subsurface formations.

Figure 7-5 presents a schematic drawing of two wells penetrating a hypothetical formation. One of the wells crosses a fault along which downward dis-

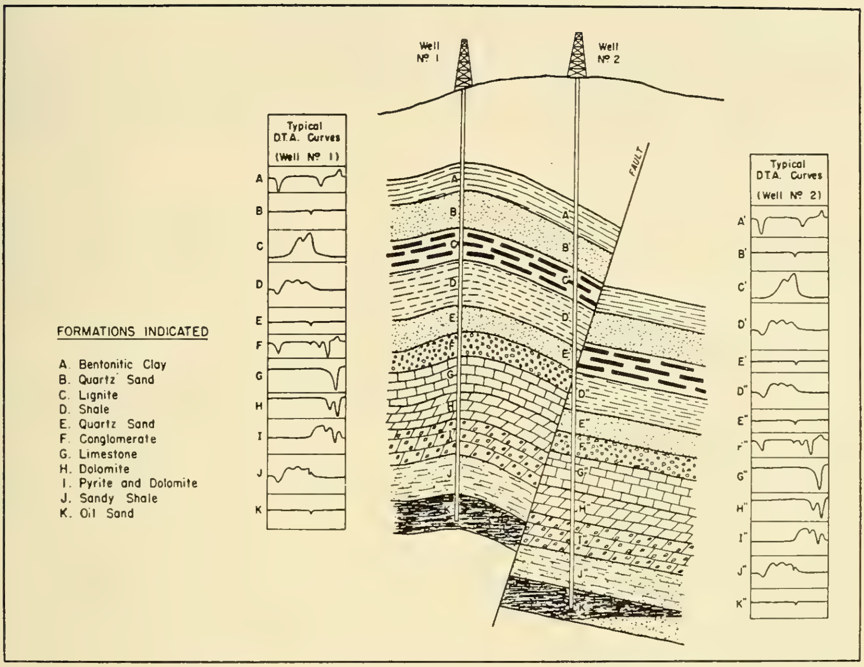


FIGURE 7-5. Schematic correlation of zones with DTA.

placement has occurred. For purposes of illustration, various types of common lithologies have been included in the drawing and typical DTA curves representing each are shown alongside. These curves have been rotated 90 degrees clockwise from the examples previously shown. In other words, high-temperature reactions are toward the right end of the curves; endothermic peaks extend downward; and exothermic peaks extend upward. In this position it is possible to present the curves in the form of a log with the base line of each sample plotted against depth.

As well No. 1, in Figure 7-5, is drilled through the successive formations AK, each provides samples whose DTA curves resemble those indicated in the simplified log at the left, with obvious breaks occurring between each formation. When well No. 2 is drilled, correlation with No. 1 is desired. DTA is determined on cutting samples and at some depth A′, the curves are similar to those of well No. 1 at A. Succeeding zones B′, C′, D′, and E′ compare respectively with B, C, D, and E and provide good correlation. Below E′, where the fault is penetrated, an immediate difference is obvious. Study of the ensuing portions of the logs, however, show that D″ and E″ are repeats of D′ and E′, while F″K″ again correspond with sections FK of well No. 1. The DTA logs of these two wells not only show correlation of the formations and establish the location of the oil sand, they also indicate the presence of a fault, spot the depth at which it was encountered, and provide a means of determining vertical displacement. Thermal curves for the weathered-surface-soil mantle, an assortment of clay and organic complexes, have been omitted.

PROCUREMENT OF SAMPLES

The first and one of the most important steps in preparing a DTA log is the proper selection of cuttings (or cores). It has been found that with good drilling-mud control, there is little danger of bottom cuttings being contaminated with materials from depths higher in the hole. The main problems are (1) selection of significant intervals for sampling, (2) correct identification of depths, which can be done if periodic lag-time measurements are made (3) sufficient but not excessive washing to remove adhering drilling mud, and (4) drying at a temperature low enough (maximum of 180F or 82C) so that clay water-of-hydration or mineral water-of-crystallization is not driven out.

Of these problems, only 1 and 3 need be considered in more detail. If cuttings are used, experience has shown that the DTA run on samples at 20-foot intervals normally provides sufficient delineation for the main body of the log. However, where lithologic breaks occur, it is advantageous to have intermediate samples whose thermal curves may be inserted into the log to define more sharply the points of change. Therefore, 10-foot increments are desirable, or even 5-foot when rate of penetration allows.

Samples taken from cores generally require hand compositing. It is preferable to sample a core at 1-foot intervals, to composite 5 consecutive samples, and then to treat the aggregate similarly to a 5-foot ditch-cutting sample.

PREPARATION OF SAMPLES

Cores require little preparation other than removal of the outermost mud layer, provided they are not saturated with oil. Cuttings, on the other hand, must be washed of drilling fluid as soon as possible. If clay-base mud is involved, washing should be over a 150-mesh screen and continued until all the mud fluid has been excluded. Extended washing must be avoided if the cuttings are clay. An experienced sampler usually can distinguish between clay cuttings and balled-up fragments of partially dried drilling mud.

Cuttings taken in oil-base mud should be washed in kerosene or some other hydrocarbon solvent, then washed in water containing considerable detergent. The sample is then rinsed in fresh water.

If the cuttings or cores contain an appreciable amount of formational crude oil, it is necessary to remove this oil by accepted extraction- or low-temperature distillation methods. Retorting, however, cannot be applied because the temperatures involved would nullify completely much of the subsequent DTA reactions. After the samples are washed and cleaned, they must be dried at low temperature and then pulverized to a 60- to 100-mesh size, after which they are ready for thermal analysis.

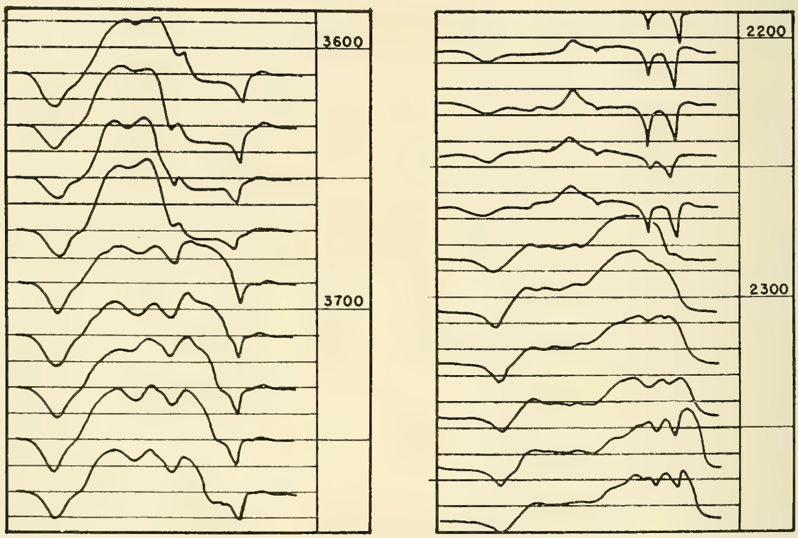
MECHANICS OF DTA

The necessary differential-thermal analysis apparatus consists of a furnace (or preferably a twin-furnace arrangement), a multiple sample holder supported in the furnace or over which the furnace may be lowered, an automatic temperature controller to provide uniform heating of the furnace, an automatic multipoint recorder for translating thermocouple millivoltage into thermal curves, and the necessary thermocouples and electrical circuits. Differential thermocouples are used; one junction extends into a sample cavity and the other into a similar cavity in the sample holder reserved for the inert alumina. Optimum rate of temperature rise in the furnace generally is considered to be from 600 to 900C per hour, with the rate maintained as nearly constant as the controller can provide. Range of temperature covered should be from room temperature to 1000C. Higher temperatures sometimes are desirable for identification of certain minerals but are not practical for most correlation works. Chromel-alumel thermocouples have been found most satisfactory because of their reasonable cost, high sensitivity, uniformity, and their nearly straight-line millivoltage-temperature relationship. A more complete description of DTA equipment adaptable to subsurface correlation work has been presented by Kerr, Kulp, and Hamilton (1949); and by Kerr and Kulp (1951).

DTA LOGS

Thermal curves, determined by means of the apparatus just described, must be corrected as necessary to delete any drift of the base lines due to slight thermal nonuniformity in the sample holder and furnace, and to minute differences in the thermocouple-junction welds. Such drift can be determined periodically by making blank runs with alumina in all sample cavities. After correcting, the curves are reduced to the desired size by pantograph or photography, and plotted on the log so that each base line coincides with the correct corresponding depth. The scale usually employed is the same as that of electric and radioactivity logs, i.e., 1 inch = 50 feet. This scale standardization makes comparison easy.

Figure 7-6 shows reproductions of small sections of actual DTA logs. Figure 7-6A illustrates an obvious break between two rather complex mineral assemblages. The formation down through 3670 feet is a shale containing considerable organic matter, a low percentage of calcite, and some quartz. At 3690 feet and below, quartz has disappeared and pyrite is present in amounts of 10 to 15 percent. Clay and calcite remain, but the organic matter is changed. Though closer identification of mineral content of these two formations would be difficult without more involved testing procedures, it is not necessary for correlation purposes. Anyone without experience in DTA can spot quickly the sharp break between 3670 and 3690 feet. Contoured curves from another well showing the same type of break would establish a possible correlative point, regardless of identification of all mineral components.



A B

FIGURE 7-6. Sections of DTA logs.

Figure 7-6B is another example from an actual well log. In this instance the upper curves (shallower formation) show a dolomitic sand containing very little clay and carbonaceous material. Between 2265 and 2285 feet, a sharp change to a pyritic clayey shale occurs. Dolomite (the double endothermic peak) at first disappears at this break but comes in about 25 feet deeper and increases in concentration with depth. This point is a potential correlative marker that is obvious even to the untrained eye.

CORRELATION OF DTA LOGS

Wells cannot be correlated safely on the basis of one or two DTA markers such as were pointed out in Figures 7-6A and 7-6B. Extended sections should be tested by DTA so that various trends, markers, maximum and minimum concentrations of particular minerals, and definite formation breaks appear. Then, when a corresponding log is obtained from another well, the validity of correlation can be established. Due to stratal thinning and to variations in structural dip, the footage interval involved in the penetrated section may vary considerably between wells. Emphasis must be placed on the sequence of zones in the overall well profile.

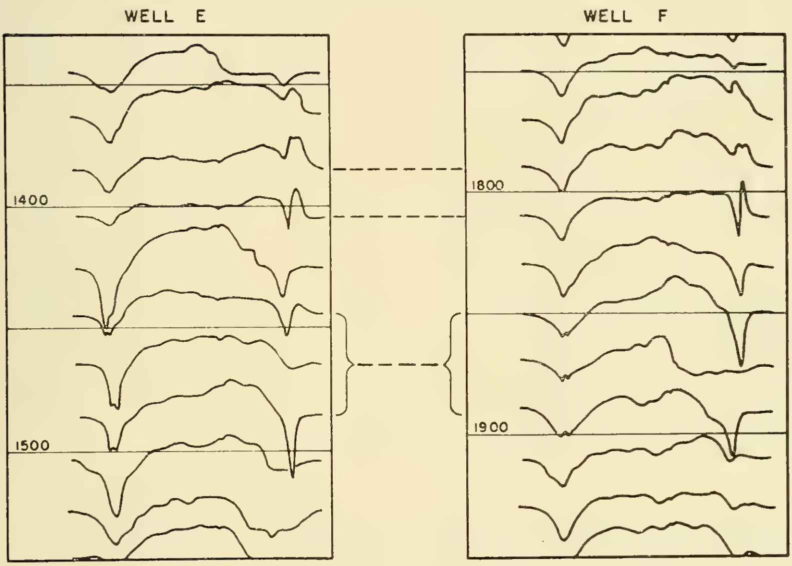


FIGURE 7-7. Correlation of thermalogs.

Only limited sections of logs can be used as examples in this chapter. In every instance where correlation was achieved, it was based not only on the portion illustrated but on overlying and underlying footages. The figures merely serve to exemplify the manner in which correlation is obtained.

Figure 7-7 is a reproduction of corresponding sections from two DTA logs successfully correlated even though no major breaks appeared. Without attempting to identify the mineral reactions which produce the curves, the following peaks are significantly similar between the wells.

1. Double low-temperature endothermic peak extending for about 40 feet (1445-1485 feet, well E; 1850-1890 feet, well F).
2. High-temperature reversal at 1385 feet and 1405 feet, well E and at 1790 feet and 1810 feet, well F, with shallower depth of each exhibiting a flat exothermic plateau, while the greater depth shows a sharp peak.

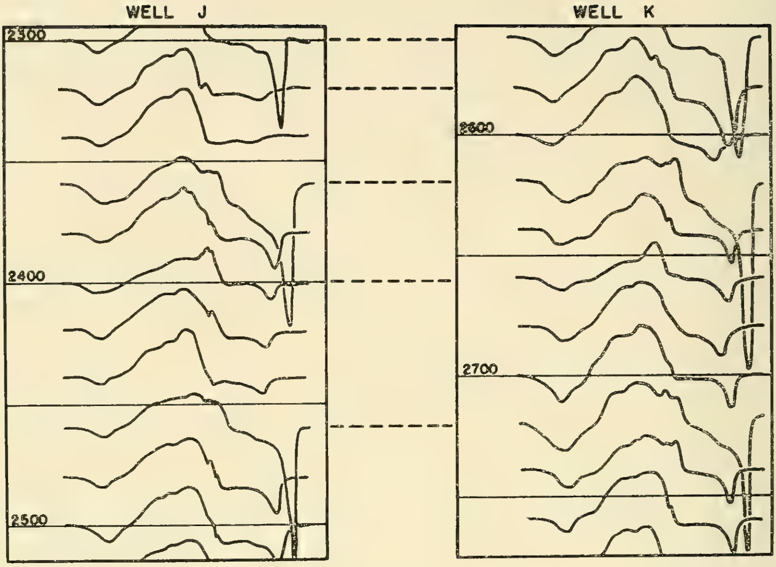


FIGURE 7-8. Correlation of thermalogs.

3. Similar variation in the high-temperature endothermic reactions (well E at 1425-1485 feet, well F at 1830-1890 feet).

Another example of correlation is presented in Figure 7-8 on which similar progression of calcite appearances (high-temperature endothermic peak) is strikingly obvious. This alone, however, would not be sufficient for accurate correlation. Additional markers, though less obvious to the untrained eye, are required for substantiation. These included such points in wells J and K, respectively, as the small mid-temperature exothermic peak at 2320 and 2580 feet, the tendency for a mid-temperature exothermic plateau at 2360 and 2620 feet, and the generally similar variations with depth of the large low-temperature (organic) hump.

DTA vs OTHER CORRELATIVE TOOLS

No tool in the petroleum industry is 100 percent successful in correlation work. This applies to the DTA and other types of cuttings analysis as well as to in-the-hole logging techniques. Whenever possible, all available sources of potentially correlative information should be used and properly integrated. In many instances, one method will give the desired results while another will not.

The wells J and K of Figure 7-8 were correlated by DTA. In this instance, other available correlative tools were unsuccessful. Figure 7-9 shows sections of electric logs of the same two wells. The electrical profile of well J did not provide good markers or zones and almost led to a false correlation. Regardless of whether or not a correlation is valid, a best possible correlation can be achieved between nearly any two sets of corresponding data obtained during the drilling of two wells. The most dangerous pitfall in the use of DTA for correlation is the same as for any other correlative tool—the tendency to correlate logs from a single zone or limited stratigraphic interval. It is essential at all times that a clear and realistic approach to correlation be maintained, no matter what type of equipment or logging method is involved.

Figure 7-10 illustrates good agreement between DTA and an electric log through the same formations. The obvious sands indicated by the electric log appear on DTA as more nearly straight lines with decided diminution of clay and organic reactions and vast increase in quartz content. Furthermore, the sands are not calcareous although the shales on either side are somewhat calcareous. It frequently happens that otherwise unexplained resistivity development on electric logs can be clarified by thermal analysis. High concentrations of dolomite, for instance, will yield high resistivity in almost all instances, regardless

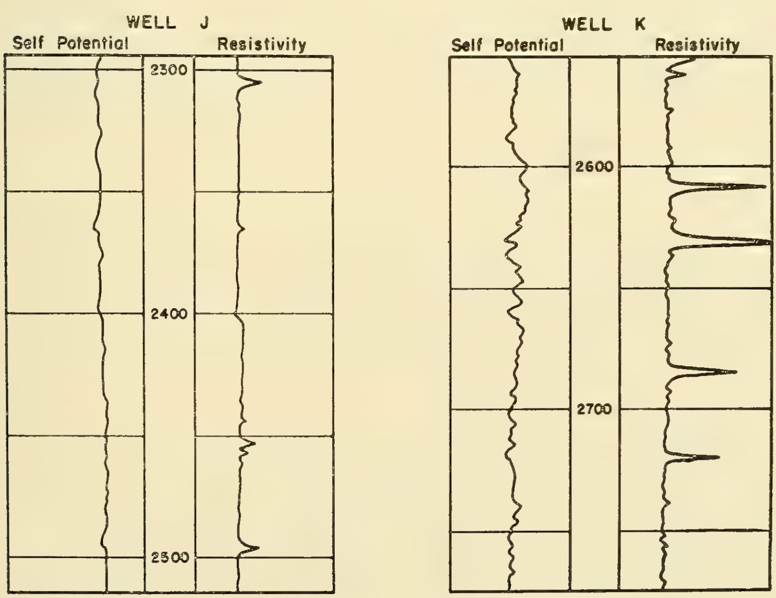


FIGURE 7-9. Electric logs.

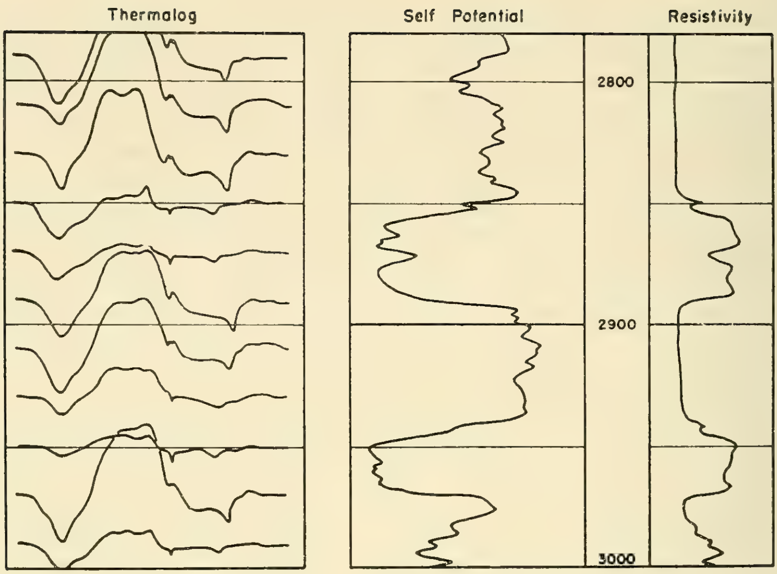


FIGURE 7-10. Correlation of thermalog and electric log.

of the formation fluids present. Likewise, naturally conductive solid minerals will have the reverse effect.

Another example to emphasize the necessity of using all available correlative tools is shown in Figure 7-11. The section covered by DTA is the one previously shown in Figure 7-6A in which a sharp major break separates two types of shales. The electric log for this section, however, failed to distinguish appreciably between the shales because of lack of change in formation fluid content and permeability.

In comparison with paleontological correlation, DTA agreement has been excellent (Mangold, 1955). Here again, the need for more than one correlation approach is demonstrated. In many formations fossils are not present. In some formations faunal migration has caused anomalies that tend to confuse and obscure correlation. The wells represented by DTA in Figures 7-7 and 7-8 did not yield fossils. The break in Figure 7-11, however, was accurately spotted by microfaunal change.

In comparison with other techniques based on mineral analysis, DTA offers decided benefits. For many correlation programs, thin-section analysis is expensive—as is chemical analysis. Spectrographic analysis is feasible sometimes and may supply some correlative data; but, like chemical analysis, it gives results in terms of elements rather than of compounds and mineral aggregations. Attempts have been made to correlate wells by microscopic observation and de-

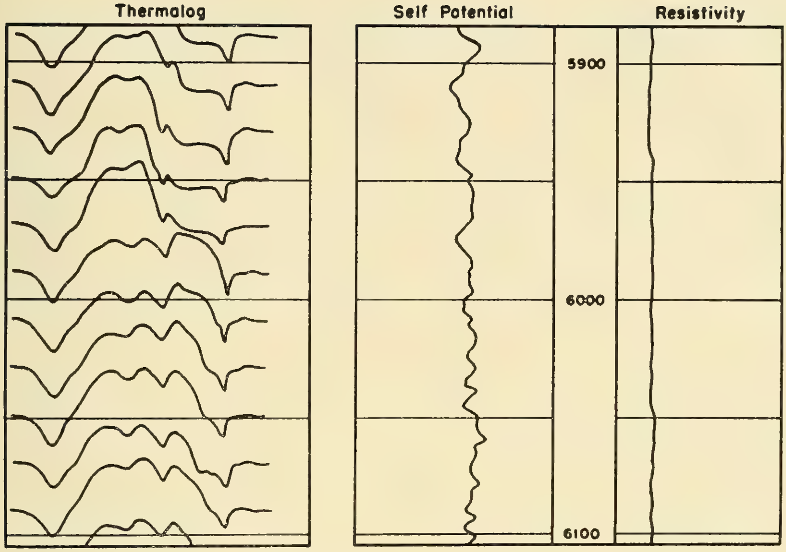


FIGURE 7-11. Thermalog formation change vs. electric log.

scription of cuttings, but even with very competent geologists, the human element enters into the technique to such an extent that correlations are frequenly impossible except over very short distances. Many variations not apparent to the eye are recognized by the DTA. Figure 7-12 illustrates sections from a formation described merely as undifferentiated volcanics. The thermal curves show weathering and alteration to an almost unbelievable extent and could provide correlative clues in a zone where little other information would support a correlation.

ADVANTAGES OF DTA

There are many advantages of DTA for correlation work which have not been covered or which have only been mentioned briefly. The advantages given below should be considered in any drilling program.

Primary Nature of Property Measured

DTA is a measurement of the basic primary composition of the formation and is not affected by accompanying environmental conditions. In-the-hole logging techniques are dependent on secondary effects, and the properties measured are complex resultants due not only to the mineral assemblages but also to particle size, type of cementation, formation fluid, permeability, surface phenomena,

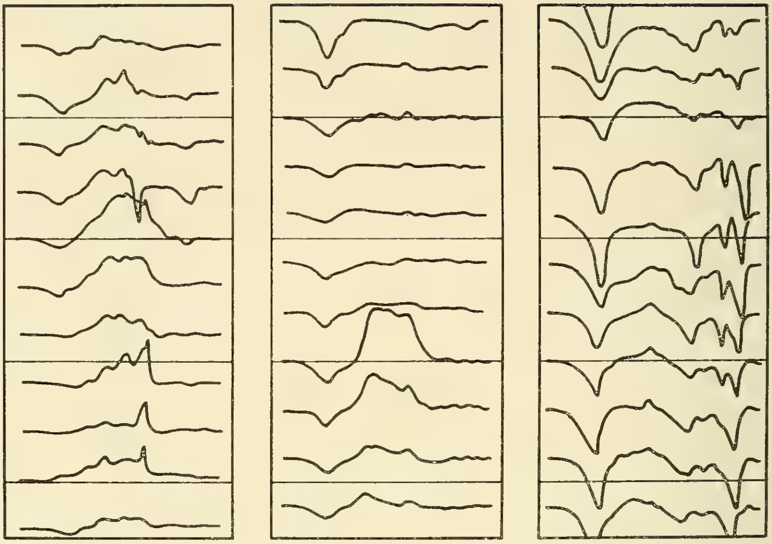


FIGURE 7-12. Differentiation of volcanics by thermalog.

and even the type and composition of drilling fluid. These measurements depend upon the sum total of the physical and chemical environment. In contrast, for DTA each mineral must be identified in its own right; no combination of phenomena or grouping of properties can "produce" a mineral that is not there.

Minimum Effect of Human Element

The human element does not enter into the actual determination of thermal curves. After the samples have been loaded into the holder, control of temperature rise and recording of thermal reactions are automatic. Although identification of constituents is a matter of experience and training, correlation can be based purely on the similarity or dissimilarity of curve characteristics.

No Loss in Rig Time

DTA does not involve cessation of drilling and loss in rig time. The source of material for analysis is always present in the form of cuttings while drilling is in progress.

Flexibility in Time and Location

DTA can be determined in a nearby laboratory, or in a laboratory thousands of miles away. It can be done while the well is being drilled or at any later date. If samples are washed and preserved properly, they need not be tested until such time as a second well is drilled and correlation is desired. The samples need not be large. As little as two or three grams will suffice. They may be shipped air mail in small envelopes quickly and inexpensively.

Speed of Determination

With a twin-furnace arrangement and multiple-point recording, DTA can proceed at a rate of about 100 feet per hour, assuming normal 20-foot sample intervals. This speed will keep up with usual drilling rates. Where drilling is faster, a wider spacing of samples can be used with subsequent fill-in if desired for further delineation of correlative breaks.

Low Cost

All other correlative techniques comparable to DTA in potentiality are more expensive. In-the-hole logging involves idle rig time; paleontology requires extensive sample preparation and thoroughly trained observers; but, DTA can be handled by semi-skilled personnel.

Source of Additional Information

DTA provides other information than correlative. It may give semiquantitative analysis of mineral composition for aid in determining the geologic history of a stratigraphic section; source rock, possible corrosive effects on pipe, drilling-mud contamination, cement contamination, and effects on in-the-hole logs.

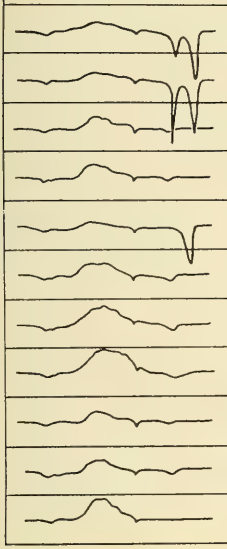
One of the most rewarding avenues of research in the evaluation of subsurface minerals by DTA is the study of carbonates, particularly the dolomites. DTA techniques can differentiate easily between types of carbonates and are sufficiently sensitive to detect effects of minute amounts of dissolved salts upon the decomposition reactions. For instance, in a mixture of calcite ($CaCO_3$), dolomite ($MgCO_3 \cdot CaCO_3$), and magnesite ($MgCO_3$), not just two but four decomposition peaks result, with the double peak of dolomite remaining independent of the separate decomposition reactions of calcite and magnesite. The effect of small amounts of soluble salts—particularly the chlorides—in altering the shape and characteristics of the dolomite decomposition has been studied widely by DTA and is providing much new information relating to the environmental conditions of source rock and the geologic age of these formations (Berg, 1943; Graf, 1952). Other evaluation techniques applied to dolomites and other carbonates are available in the literature. These include studies of hydrothermal solution sources of dolomite (Faust, 1949), distribution of oil in relation to source rock (Hunt and Jamieson, 1956), correlation by thermoluminescence (Bergstrom, 1956; Pitrat, 1956), grain size of carbonates vs environment of deposition (Ginsburg, 1956), Ca/Mg ratio in relation to porosity (Chilingar, 1956a), and Ca/Mg ratio as reflected in geologic age (Chilingar, 1956b). DTA can be a great help in complementing other lines of research and in presenting new as well as corroborative evidence for more comprehensive stratigraphic evaluations.

In the study of formation environments, an increasing emphasis on the use of clay-mineral identification is appearing in the literature. W. D. Keller (1956) has pointed out recently the potentialities of this line of approach in determining characteristics of source rock and the physical and chemical factors prevailing during the clay deposition. Here again DTA can be an invaluable tool, and it is already widely accepted in certain industries for clay-mineral evaluations. In an extensive study of clays from the Ione formation, Amador County, California, Pask and Turner (1952) employed various techniques in addition to DTA but found the latter to be relatively simple to use and their most powerful formation-identification and correlation tool.

DTA can be of great use not only for environmental studies but for immediate practical applications of knowledge of the type and amount of clays in a formation. Flood-control projects, canal building, and land drainage are examples of engineering works which may be aided very much through the utilization of clay properties and avoidance of harmful effects of clay hydration and base exchange. In the petroleum industry, the same factors are involved in waterflooding projects, where success or failure may depend on knowledge of the concentration of swelling clays and the ability to treat injection waters in order to preserve permeability of the formation to water.

Frequently DTA may explain and corroborate apparent anomalies in core analysis by showing a mineralogical reason for changes not apparent in physical structure. Figure 7-13 illustrates this possibility. Data on 11 consecutive core samples, spaced 1 foot apart, are presented alongside the corresponding differential-thermal curves. Visually there were no appreciable differences between these samples, yet core analysis indicated many decided variations. Similarity of the first two depths, low permeabilities, and high resistivity is explained by the similar thermal curves showing considerable dolomite content. The next two samples are much alike yet quite different from the first pair. Correspondingly, porosity, permeability, and resistivity values have changed radically yet are of the same order between themselves. The sample from 8251 feet contains calcite, which accounts for the low permeability without high resistivity. And again, depths 8255 and 8256 feet appear almost identical on DTA and have almost identical core-analysis values.

DTA is potentially able to locate position of casing failures by identification of depth corresponding to composition of material being produced through the pipe break. There is an actual instance of this type on record where shale particles were apparently coming from the producing zone but were identified by DTA as formation up the hole opposite a subsequently located casing defect. A



THERMAL CURVE	DEPTH (ft)	POROSITY	K_{air}	$K_{s.w.}$	K_{oil}	RESISTIVITY	D.T.A. CHARACTERISTICS
	8247	10.2	1.4	0	0	40.7	Strong dolomite
	8248	10.6	0.3	0	0	46.2	Strong dolomite
	8249	15.7	8.9	7.8	7.2	36.3	Only trace of carbonate More shale
	8250	17.0	20.	14.	9.4	36.3	Same as 8249'
	8251	12.8	1.5	0	0	31.7	Strong calcite
	8252	16.8	24.	25.	13.	28.6	
	8253	14.6	1.2	0	0	29.1	
	8254	17.2	3.2	1.9	0	18.5	Trace of pyrite
	8255	16.6	14.	13.	7.1	26.1	Strong quartz Weak shale
	8256	14.6	16.	15.	7.3	24.5	Same as 8255'
	8257	16.0	3.7	3.6	0	20.9	No carbonate

FIGURE 7-13. Differential-thermal analysis vs. core analysis.

discovery such as this can conceivably change the whole program of drilling and production and perhaps be of economic value far beyond that of its ordinary correlative use.

DTA may indicate the presence of valuable ores contacted in drilling which otherwise might be entirely overlooked. At times these ores are so finely divided that they escape recognition by the ordinary visual or microscopic observations. Regardless of their particle size, form, or association, if they are active thermally, they will appear on the DTA log.

CONCLUSION

As with all methods of subsurface geologic analysis, DTA has limitations. In common with other types of cuttings analysis, sampling must be controlled carefully. If drilling-fluid servicing is lax, contamination may occur. Certain types of formations are inert thermally and are not detected except as dilution of active constituents is observed. However, these limitations are far outweighed by the potential discussed herein for inexpensive correlation of subsurface formations, corroboration and clarification of other logging methods, and analysis of the mineral environment encountered during drilling. Although DTA has been used only a few years in the petroleum industry, it has already proved of enormous value to geologists and engineers.

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Chapter 8

ELECTRON-MICROSCOPIC ANALYSIS

Carl A. Moore

Ability to discriminate among minute objects that lie very close together is described as the resolving power of a microscope. In spite of various methods that may be employed to increase the resolving power of a light microscope, objects separated by less than 0.1 micron (0.0001 millimeter) cannot be resolved. Thus it is that the limits of the light microscope are not the lack of skill on the part of the designer but rather are due to the light—the media used for observation.

This limitation of the light microscope is an important factor in microscopy; for example, the study of viruses must be conducted with particles and separations much smaller than this, and the study of colloids necessitates greater resolving power than that possible with the light microscope.

With the introduction of the electron microscope, this limit on resolving power has been greatly decreased, since the magnification is no longer limited by the wave length of visible light. Theoretically, the electron microscope should be capable of resolving powers as small as atomic dimensions. In actual practice, however, the microscope has not been perfected to that extent. Nevertheless magnifications of over 100,000 diameters are practical with the electron microscope, as compared with a useful limit of 2000 diameters for the light microscope.

DESCRIPTION OF THE MICROSCOPE

Figure 8-1 is a comparison of the optical microscope with the electron microscope showing equivalent parts: magnetic fields are equivalent to lenses; both have specimen levels; and both have photographic plates for pictures. For comparison, the electron microscope is diagrammed upside down.

A simplified drawing of the R.C.A. compound magnetic electron microscope, type EMB, is shown in Figure 8-2. Focusing is accomplished by varying the lens power. The specimen mount is the movable stage. As the stage is inside the vacuum portion of the microscope, it is moved by means of fine screws and a metal flexible bellows.

The electron beam is concentrated on the specimen by the magnetic field produced in the condenser-lens coil. After passing through the specimen, the electrons are focused by the objective-lens coil into an intermediate image, and the projection-lens coil produces a further magnified image on the fluorescent screen in the final viewing chamber.

To facilitate the initial adjustment of the specimen, a port is provided for viewing the intermediate image on a fluorescent screen close to the plane of the projection-lens coil. By virtue of the relatively low magnification at this point,

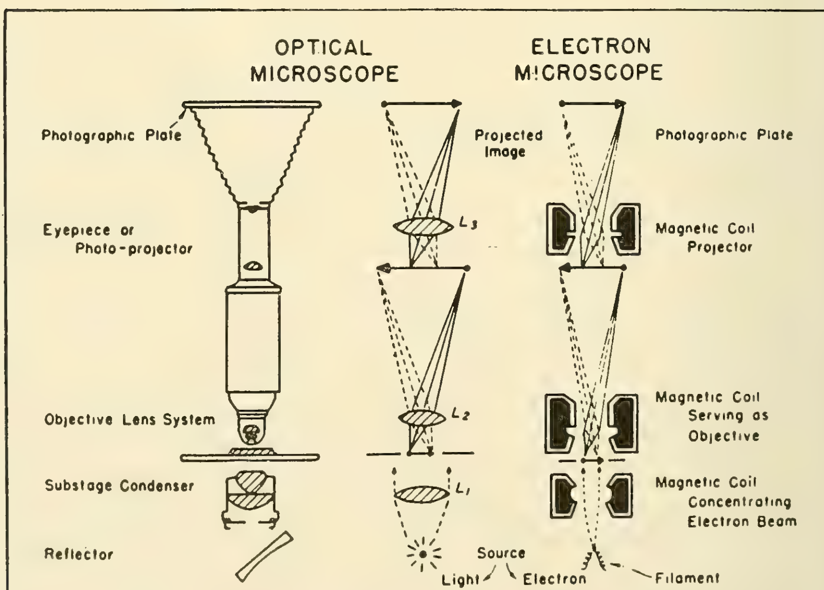


FIGURE 8-1. Comparison of light microscope and magnetic electron microscope. (Burton and Kohl)

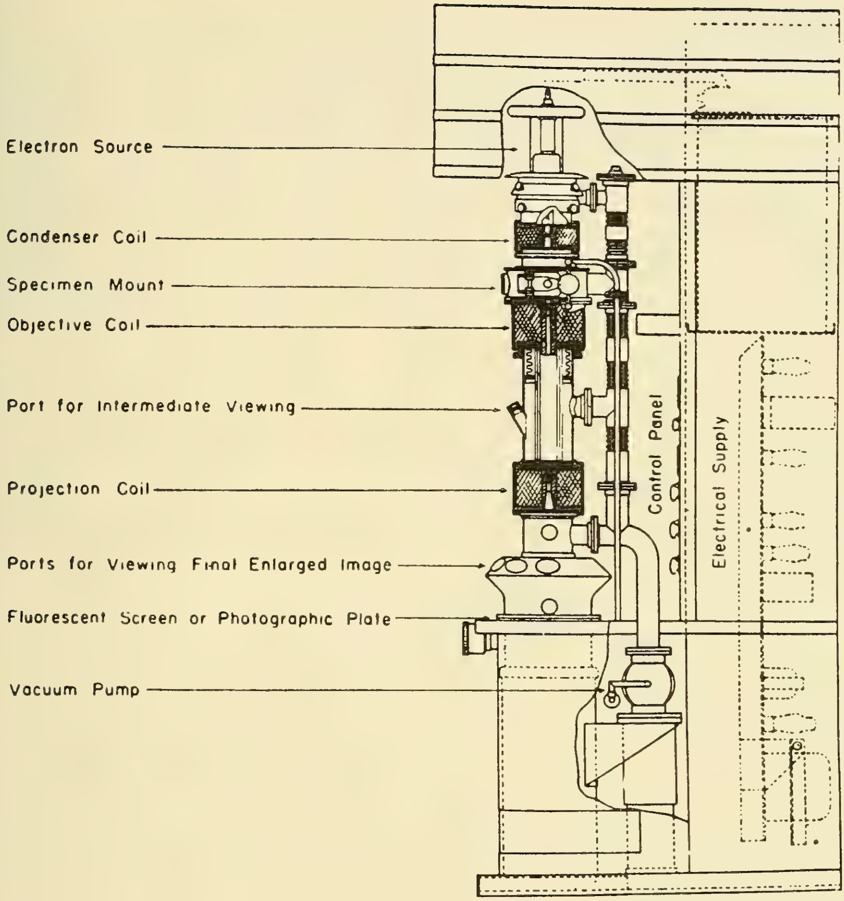


FIGURE 8-2. Simplified drawing of electron microscope, taken from "Electron Microscope" prepared by R.C.A. Manufacturing Company, Camden, N. J.

it is possible to select the most interesting part of the specimen and to move it into position to be magnified further by the projection-lens coil.

Six observation windows enable a number of spectators to view the image simultaneously. With the choice of a selected field of view and the magnification adjusted to the desired value, the fluorescent screen is raised, exposing a photographic plate to the electrons. This plate is carried in a holder in the vacuum system of the microscope. Magnifications of 1000 to 20,000 diameters are possible, and the definition of the photograph is sufficiently clear to allow further optical enlargement to full useful magnification.

SPECIMEN-MOUNTING TECHNIQUES

It was necessary to devise a special specimen-mounting technique in order to work with the small areas that are enlarged to full magnifications for study. Most specimens are mounted on a 400-mesh screen. This screen is dipped into a solution of collodion, which dries quickly, leaving a strong film approximately one micron (0.001 mm.) thick between the individual wires.

The material for study may be placed on this collodion film in one of several ways: (1) manually, under high-power binoculars; (2) precipitated from solution onto the screen; (3) by passing the screen coated with collodion through a culture of the material; and (4) by placing a drop of material suspended in a liquid onto the screen.

No wet or living tissue can withstand the high vacuum of 10^{-4} to 10^{-5} millimeters of mercury in the electron microscope. However, the microscope is being used extensively in biological studies on materials ranging in size from that of the organs of animals and insects downward through that of the bacteria and of the viruses and even of large molecules. The material in turn must be thin enough to allow the passage of electrons through it. Some materials deteriorate when subjected to the intense electron bombardment, and some materials may heat up during this bombardment. Owing to the high vacuum, this heat cannot be transmitted or conducted away from the subject.

POSSIBLE USES IN CORRELATION WORK

The usefulness of any method of correlation lies in its ability to indicate or prove the existence of equitable or similar ages or environments of deposition between two areas, two wells, or two geologic outcrops. Most methods in geology originally included only the megascopic aspects: for example, similar or identical fossils and equivalent successions of beds, to mention two. With the advances in geologic techniques, more precise correlation has been possible by utilizing microscopic similarities for correlations, as in micropaleontology, sedimentary petrology, and microlithology.

With the electron microscope, it should be possible to achieve the ultimate in utilizing submicroscopic similarities for correlations. Some uses possibly peculiar to this microscope are discussed.

Bed Identification

It is possible that many minute similarities exist in beds or formations, which, if they could be seen and studied, could be used to correlate subsurface beds. In studying sandstones, for example, it would not be possible to observe the actual sand grains, but it would be necessary to study the cementing material and any foreign material in the sandstone.

Correlations with limestones should involve a different set of conditions. As a general rule limestones are compact or, if porous, contain comparatively large pores and openings. It would be difficult or impossible to grind a thin section of limestone to a thickness allowing the electrons to pass through the specimen and produce an image on the photographic plate. The pores of the limestone are so large as to preclude any precise study of their contour or shape. For these reasons, a possible approach would lie in the study of the residues after the limestone had been dissolved in some suitable solvent. Either the filtrates could be examined for correlatable objects, or the residue, which is often largely clay, might lend itself to study in the electron microscope. This latter instance leads into the problem of the study of shales.

Correlation of Clays

According to J. Hillier (1946) ". . . particles of various types of clay have probably been subjected to more examination by means of the electron microscope than any other type of material." Some clays are composed of grains of about 50 angstroms in thickness and a few angstroms wide. Studies of the nature and correlation of such minute particles in the electron microscope depend on characteristic shapes and not on chemical combinations.

One of the clays used extensively in laboratories and refineries for filtering is called Attapulgus clay, so named for Attapulgus, Georgia. Chemical analyses of this clay show it to be chiefly montmorillonite, a hydrous aluminum silicate, but the individual microcrystalline masses cannot be identified or resolved under the best light microscope. Figure 8-3 is an electron-microscope picture of this clay, × 20,000, showing an abundance of masses of minute fibers. These fibers are the so-called microcrystalline masses that cannot be identified or resolved under the polarizing microscope.

Infusorial earth is described as a "siliceous earth made up largely of siliceous fragments of Infusoria, used as filling material and as a filtering and absorbing agent." Figure 8-4 is an electron-microscope picture of this material, × 20,000, showing fibers very similar to the Attapulgus clay. The similar shapes of constituent parts of these two materials attest to their similar physical properties.

Clays might lend themselves to study and correlation in the electron microscope in the following ways:

1. The submicroscopic mineralogy and crystallography of clays might be studied. Minute crystals of rutile have been identified in titanium-rich clays. These crystals were too small to be identified under a light microscope. Detailed studies should bring out several similar instances of submicroscopic mineralogy that could be of value in correlation.

2. The presence of submicroscopic organic forms too small to be identified

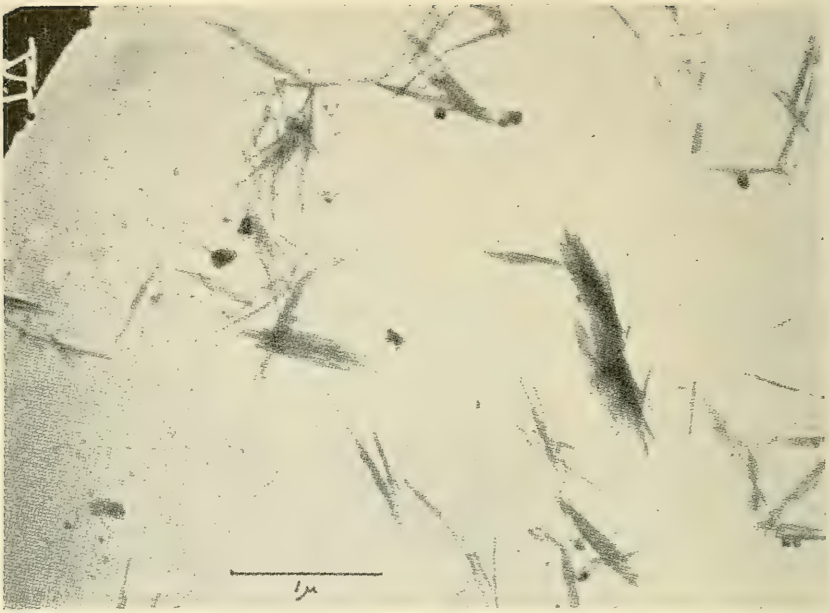


FIGURE 8-3. Electron-microscope picture of Attapulgus clay (X20,000). Note minute fibers and bundles of fibers, with very few larger grains. These average less than ⅛ μ (= 0.000125 mm) in diameter and are of colloid size. (Courtesy R.C.A. Laboratories and Standard Oil Development Company.)

or even noted under a light microscope could provide the means for bed identification. This would involve the development of electron micropaleontology, wherein organic forms far below the smallest fossil known would be studied.

3. Structural details of clays, pertaining to possible physical and physicochemical properties of the clays, should lend themselves to study in the electron microscope. The importance of this point might be stressed by suggesting that the electron microscope is believed to be capable of resolving giant molecules. At these particle sizes the physical and chemical properties would be dependent one upon the other and should be difficult to separate.

4. In the same general way, clay residues from limestones might be studied. Identification would depend upon the structural details and perhaps the mineralogy. Chemical or spectrographic methods of study would probably be of more value here than would the electron microscope.

5. Physical studies of the response of clays to the high vacuum in the electron microscope and changes due to the electron bombardment, with subsequent heating of the samples, might yield significant similarities and differences of correlative value.

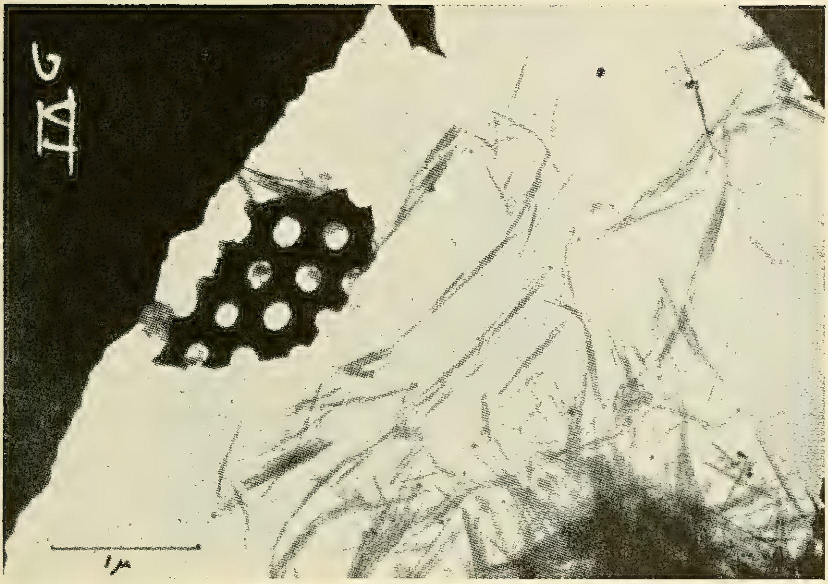


FIGURE 8-4. Electron-microscope picture of infusorial earth (X 20,000) sold by Central Scientific Company, Chicago. Note that fibers and bundles of fibers are very similar to those in photograph of Attapulgus clay in Figure 8-3. Diatom fragment near center of photograph is about $1\frac{1}{2}$ μ in length and 1 μ wide. Openings in shell are less than $^1/_5\mu$ in diameter (0.0002 mm) and would barely be discernible in the light microscope. (Courtesy R.C.A. Laboratories and Standard Oil Development Company.)

Long-Range Correlation

The foregoing discussion has involved detailed correlations between individual beds. It was pointed out that electron-microscope techniques are not in general use as yet and may not be used except in unusual cases. Long-range correlations, of course, depend upon equivalent criteria being found over long distances. For this reason, long-range correlations with the electron microscope are subject to the same considerations as were the closer, detailed correlations.

Studies of Crude Oil

It will be necessary to develop a technique for studying crude oils in the electron microscope. A possible approach to this study may be as follows:

1. All foreign substances in the oil and in the extracts that are possible to prepare for study in the microscope would be studied.
2. Bacteria in the oils and in the extracts would be observed and identified.
3. The nature of coloring material in some of the darker oils would be studied. Is color due chiefly to the presence of foreign materials, or could it be due to molecular combinations?

4. The behavior of the oil and extracts during preparation would be studied, and the reactions to the high vacuums and to the electron bombardment observed.

5. The R.C.A. engineers and research physicists have photographed in the electron microscope what they believe to be giant molecules. Molecules of crude oil are believed to be disposed in some sort of regular pattern and may be quite large. Perhaps actual molecular differences may be found in crude oils, in the extracts, or in the various fractions that may be used for correlation.

Paleontologic Studies

Generally speaking, paleontologic specimens are too large for study in the electron microscope. It should be valuable, however, in studying details of fossils too small for study under a light microscope, such as diatoms, spores, algae, and some protozoans. A comparison of diatom shells photographed with a light microscope and the electron microscope shows that under the light microscope the number and arrangement of the perforations can hardly be determined, whereas the electron microscope indicates clearly the detail, arrangement, and number of perforations.

The electron microscope has opened up a new realm of research and endeavor. It is being adapted to a great number of scientific fields both for research and for industrial purposes. Future developments should increase the resolving power far beyond the best that is available today, but, conversely, this increase in resolving power will be one of the limiting factors of the microscope, because by working with very minute objects it is not possible to mount particular specimens for study. Most geologic techniques do not require these extremely high magnifications, however, and things geologic are usually too large for these magnifications. Further research in strictly geologic fields will have to be limited to particular problems where the microscope can be fully utilized.

Reprinted from *Subsurface Geologic Methods,* 1951, p. 202-211.

Chapter 9

X-RAY ANALYSIS

N. C. Schieltz

Within the past half century the use of X-rays has been developed as an analytical tool to an extent that today it is considered as one of the most versatile and reliable methods of analysis, as well as a powerful research tool. X-rays can be used equally well for diffraction studies or emission spectrographic analysis to determine of which elements a substance is composed; how these elements are combined to form molecules or how they are space packed to yield our ultimate crystal structures. These analyses may be purely qualitative or they may be designed to give quantitative results. The results of the analysis may be recorded by conventional film methods or by the use of counters (proportional, geiger, photo multiplier, etc.) combined with suitable strip chart recording mechanisms. For a discussion of these methods the reader is referred to standard books on the subject (Cullity, 1956; Klug and Alexander, 1954; Davey, 1934; Bunn, 1946; Clark, 1955; Bragg, 1955; Buerger, 1942; Guinier, 1952; Henry, Lipson & Wooster, 1951; Barrett, 1952). This discussion will be limited to such information as is necessary for the identification of materials of interest to the geologist.

These methods are extremely advantageous since by means of them we can determine not only which elements are present (with limitations) but also their combinations while forming the various mineralogic species. Furthermore, the methods are non-destructive, so that the same sample specimen can be used for further studies by other methods when only limited amounts are available. Likewise for diffraction analysis, microscopic samples weighing no more than several micrograms are sufficient for the analysis. Finally, the diffraction patterns constitute a permanent record which is usually complete regardless of how limited the information desired was at the time the pattern was recorded.

This discussion is directed principally toward a reading audience which may have only a limited acquaintance with X-ray-diffraction methods. Consequently, a very brief discussion concerning the mechanism of diffraction appears desirable. All crystalline matter is composed of atoms or molecules arranged in definite forms of geometric space packing and in such a manner that they form definite families of planes in various directions through the crystal. By considering primary X-rays to be reflected by these planes within the crystal, the Braggs were able to reduce von Laue's original mathematically complex analysis of this interaction between X-rays and crystalline matter to much simpler terms. In Figure 9-1 two planes, AB and CD, represent one of the many families of planes found in a crystal. Two rays, *emf* and *gnoph*, of the defined X-ray beam are shown to be partly reflected from these planes when striking them with an incident and reflected angle of θ. According to the laws of optics these reflected rays must be in phase to be observed as a reflection. Consequently, ray *gnoph* must be longer than ray *emf* by an integral value of the wave length λ. Inspection reveals that this path difference is the distance nop and the no $=$ d sin θ, and $op = d \sin \theta$; thus $nop = 2d \sin \theta = n\lambda$, which is the statement of Bragg's law.

Although this equation is satisfactory for calculating diffraction effects, it nevertheless reveals little of the actual diffraction mechanism involved. A reasonable understanding of this mechanism can be gained from a familiar two-dimensional analogy of the interaction of waves on water. Figure 9-2

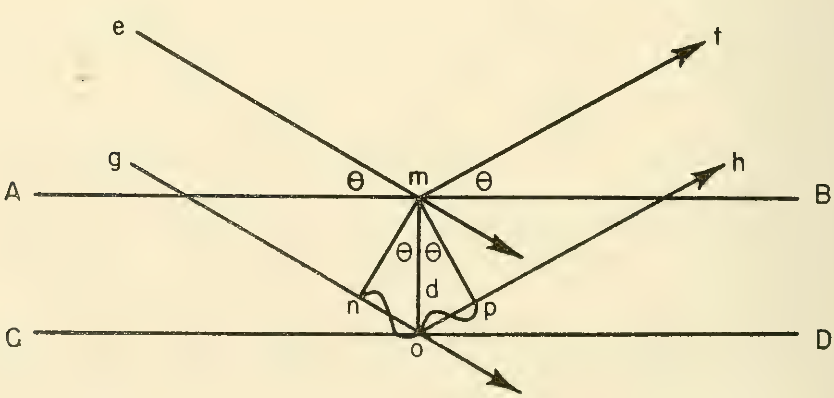


FIGURE 9-1. Reflection of X-ray beam from planes in face of crystal.

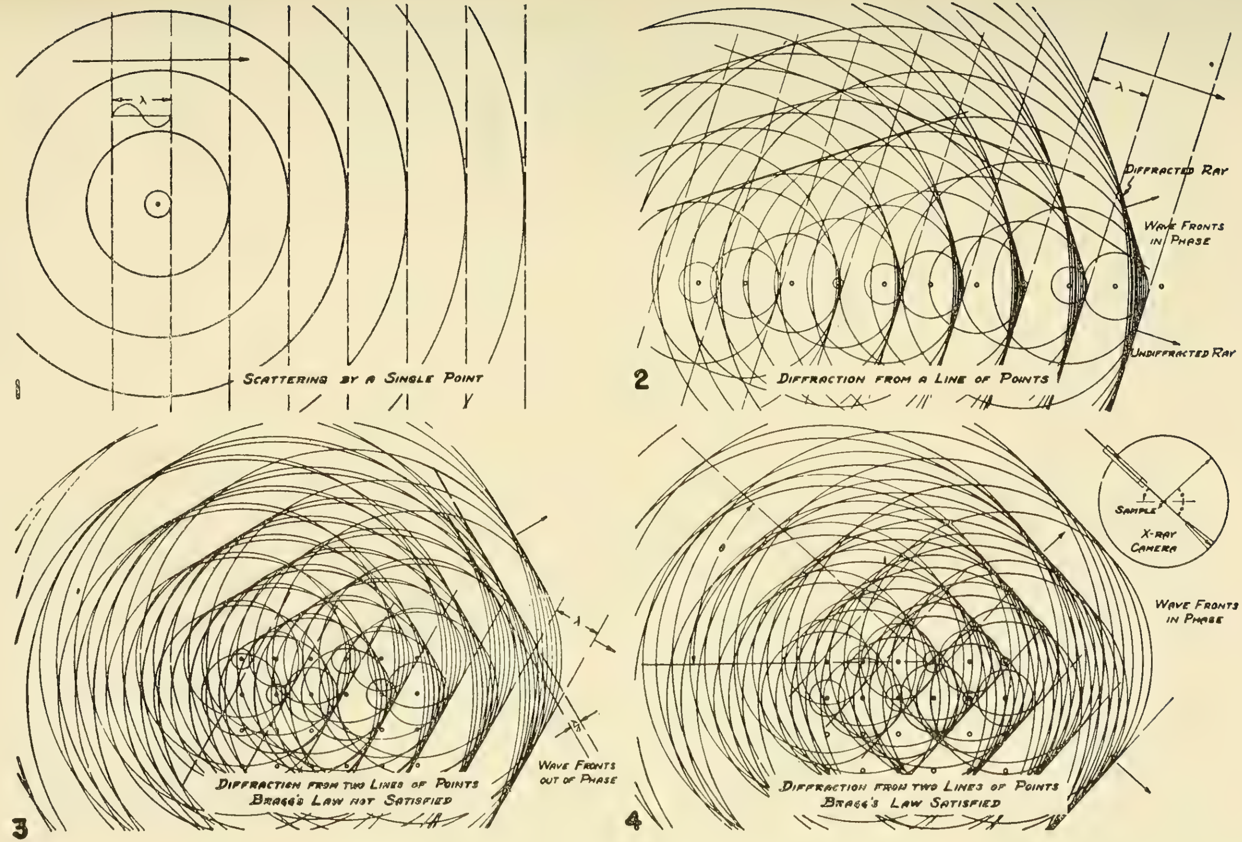


FIGURE 9-2. Schematic illustration of diffraction mechanism.

shows in successive steps (1) the generation of a circular set of waves from a series of parallel wave fronts by a post (or other small object) in a quiet body of water; (2) the interaction of these newly generated circular waves from a row of equally spaced posts produced new diffracted wave fronts; (3) the interaction of these generated circular waves from two rows of posts (two planes) under conditions where Bragg's law is not satisfied; and finally, (4) the interaction of these waves where the angle θ has been so chosen that all conditions for the observance of diffraction effects by this particular family of planes have been satisfied. The fact that the diffracted wave fronts from each row of posts are one-quarter of a wave length out of phase with those diffracted by the adjacent rows, under the conditions where Bragg's law is not satisfied, immediately shows that we cannot observe any diffraction from this family of planes under the selected conditions. On the other hand, when the angle θ has been so adjusted that Bragg's law is satisfied, all these wave fronts coincide: that is, they are in phase, and diffraction effects from this particular family of planes are observed. A sketch set into the figure shows how this phenomenon is related to conditions in the X-ray camera. The directions of the original and diffracted beams are shown by arrows and have the same directions as the labels in part 2 of Figure 9-2.

This simple two-dimensional analogy can be applied to the three-dimensional diffraction of X-rays by crystalline matter if the posts are replaced by a regular assemblage of points (atoms or ions) distributed in space at a distance that is of the same order of magnitude as the wave lengths of X-rays. Spherical waves are created when X-rays, which are electromagnetic waves, cause forced oscillations of the planetary electrons of the atoms which they traverse, the electrons absorbing energy from the X-rays when moving away from the nucleus and radiating energy in all directions when moving toward the nucleus. Inspection reveals that this three-dimensional point system will produce very narrow pencils of rays only in those directions in which these spherical waves are in phase. These reinforced waves are the rays that produce the individual spots in X-ray patterns (Laue, rotation, Weissenberg, etc.) obtained from single crystals. If the single crystal is replaced by a large number of smaller crystals, that is a powder, the 2θ angle with the undiffracted beam must remain constant since, in Bragg's equation, d for the particular set of planes and the wave length, λ, of the X-rays from a particular target material are fixed. The crystals of the powder with their statistical orientation, unless preferred orientation effects result owing to peculiar crystal shapes, then must produce a whole series of such discrete pencils, so that as a result a continuous diffraction cone with an apex angle of 4θ is obtained. If this cone is now recorded on a photographic film placed perpendicular to the cone axis, the diffraction effect is obtained as a line which is in the form of a ring. A pattern on which the diffraction rings from all families of planes have been recorded is usually referred to as a powder pattern and consists of a series of concentric rings on a flat film, or arcs of rings on a cylindrical strip of film.

A careful study of Figure 9-2 shows that a fixed space arrangement of atoms with definite fixed distances between them must always produce precisely the same X-ray pattern. Furthermore, if the space arrangement is retained but the distances between atom centers are changed, the X-ray pattern will retain its same general appearance but will either expand or contract. On the other hand, if the space arrangement is altered, the pattern is changed. Consequently, X-ray diffraction patterns are a sort of fingerprint of crystalline materials. Each individual substance present in a mixture will produce its unique diffraction effects, so that the pattern derived from the mixture is a composite of the patterns of all the materials or compounds in the mixture. Furthermore, the intensities of the lines of the individual patterns are functions of the relative amount of the material present in the mixture, so that the method also has quantitative aspects.

However, the X-ray-diffraction method is sometimes considered rather limited as an analytic tool because the relative sensitivity requires that an appreciable amount of a constituent (from 1 to 30 percent) (Brosky, 1945) must be present in a mixture before its presence can be detected. Some materials with patterns having reasonably low background intensities and fairly strong lines can readily be detected in concentrations as low as one-half to 1 percent, whereas other materials with weaker patterns, can only be detected when present in considerably larger amounts. Limitation of the number of detectable consituents in mixtures due to crowding of lines is considered a drawback by some workers using small-diameter cameras with large pinhole systems (Brosky, 1945). The use of larger camera (10 to 20 cm) diameters, smaller pinhole systems, and longer radiation wave lengths to spread out the patterns and increase the resolution should increase this number considerably. A very important disadvantage of the method is its inability to detect amorphous phases, such as glasses, when present in only limited amounts, and the fact that solid solutions may not always be observed.

APPARATUS FOR RECORDING THE DIFFRACTION PATTERNS

Two general types of apparatus are commonly used for recording the X-ray-diffraction pattern. The difference in these types of apparatus arises in the manner in which the X-ray-diffraction patterns are recorded; one type uses the conventional diffraction camera with photographic film registering differences in line intensities as line blackness, and the other, a counter tube with a scaling circuit that may be used to measure the intensity of the diffracted rays, records intensity either by the counting technique or by automatic recording apparatus. The principle of the conventional film camera type is shown schematically in Figure 9-3 and the counter-recorder type in Figure 9-4.

Film methods for recording diffraction patterns are less subject to instrumental variation than counter methods; are more positive in recording weak lines and, likewise, record other effects such as orientation effects. Hence, even if these methods are somewhat slower than the counter methods, they do produce a complete and permanent record which is easily interpreted and much more convenient to store than strip chart records.

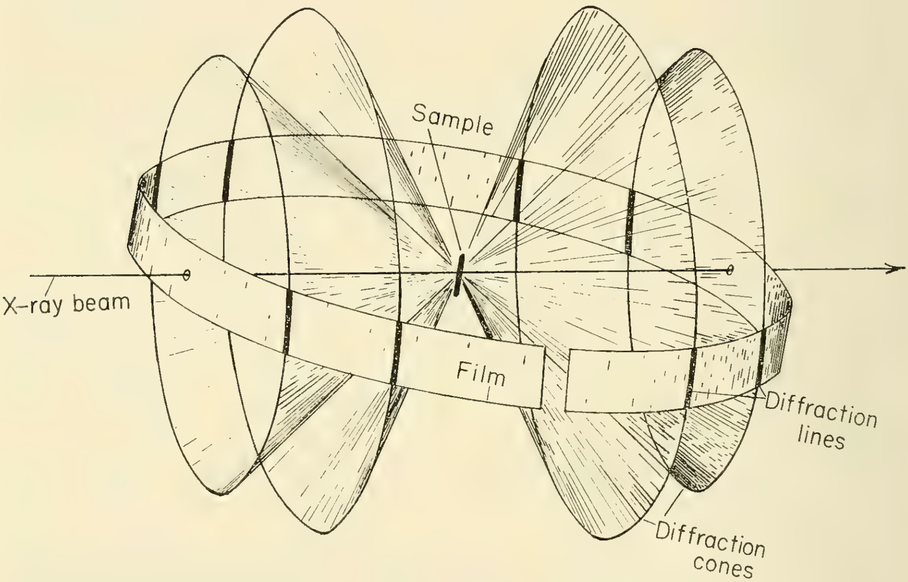


FIGURE 9-3. Schematic diagram showing principles of the conventional powder camera.

SELECTION AND PREPARATION OF SAMPLE SPECIMEN

Not enough emphasis can be placed on the selection of the sample for analysis. Because only a very small fraction of the sample placed in the camera is actually exposed to the X-ray beam, it is imperative that all precautions be observed in the choice and preparation of the sample. The sample used must be truly representative of the material being investigated as regards composition, structure or other characteristics for which the sample is examined.

Single Crystals

Single-crystal patterns are seldom made when identification of the material is the only objective, as the powder method is usually considerably simpler.

There may be occasions, however, when the sample is limited to a very small, pure single crystal, insufficient in amount to grind into powder. Under such circumstances, a single crystal ranging from 0.5 mm to several hundredths of a millimeter in cross section and from several millimeters to about 0.3 to 0.5 mm is mounted on the end of a small glass rod or wire, with one crystallographic axis approximately parallel to the axis of the rod so that it can be mounted and adjusted in the goniometer head of the single-crystal camera to turn about this axis. Patterns are recorded successively with alternate rotation about the three

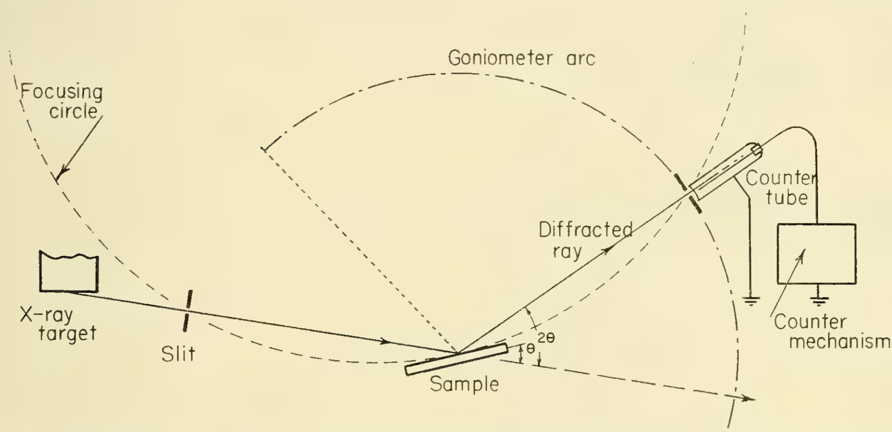


FIGURE 9-4. Schematic diagram showing principles of the counter-recorder type of apparatus.

crystallographic axes according to procedures found in standard texts (Buerger, 1942). From these patterns unit-cell calculations are made. Under adverse conditions it may be impossible to obtain patterns about all the crystallographic axes, whereupon it may be necessary to calculate the dimensions of the entire cell from a single rotation pattern by means of the reciprocal lattice. A discussion of this concept is beyond the scope of this chapter, but it may be found in text books on X-ray-diffraction techniques (Clark, 1955; Davey, 1934; and Bunn, 1946).

Powders

For powder patterns it is usually recommended that several milligrams of representative material be crushed and ground in an agate (or mullite) mortar until the entire specimen will pass a 200-mesh silk bolting cloth or screen. The writer has observed that if the sample is turned or oscillated during exposure to the X-rays it will be sufficient to grind the sample until highlights from individual particles are no longer observed when the powder is examined in a bright light while still in the mortar. If the material does not grind readily, it may be filed with a clean single-cut fine-tooth file, using no more pressure than is absolutely essential. If the specimen must be preserved in its original form, the specimen can be mounted in a suitable rotating or oscillating device in such a manner that the sample-to-film distance remains constant.

Before the method of mounting the powdered specimen is selected, the optimum thickness of the sample to be used should be determined. The proper thickness can be calculated if sufficient information is available concerning the specimen. Otherwise, the optimum thickness usually can be estimated approximately by an experienced operator from the amount of the undiffracted X-ray beam that penetrates trial specimens, as determined with a fluorescent screen. This thickness can be calculated from the equation

$$t = \frac{2}{\mu}$$

where μ is the linear absorption coefficient calculated from the mass absorption coefficient according to the relationship;

$$\begin{aligned}\mu &= d\sum p\left(\frac{\mu}{\rho}\right)\\ &= d\left[p_A\left(\frac{\mu}{\rho}\right)_A + p_B\left(\frac{\mu}{\rho}\right)_B + p_C\left(\frac{\mu}{\rho}\right)_C \cdots\right]\end{aligned}$$

d being the density of the material, p the elemental fraction in the compound and $\frac{\mu}{\rho}$ the mass absorption coefficients of the elements for the wavelength of the radiation used. The values for $\frac{\mu}{\rho}$ can be found in table form in volume 2 of "International Tabellen zur Bestimming von Kristallstrukturen" (Cullity, 1956 or Barrett, 1952).

For materials of high atomic weight the optimum thickness may be so small as to necessitate dilution of the crystalline material with amorphous diluents such as flour, cornstarch, or gum tragacanth (Davey, 1934; or American Society for Testing Materials, designation E43-42T, 1942). In any case, however, these diluents should be avoided or kept to a minimum since some of them (e.g., raw cornstarch) produce a crystalline pattern of their own, or an amorphous pattern with very broad lines (halos). These superposed patterns of the diluents often cause a considerably localized background fog, with consequent difficulty in observing lines in the regions of the amorphous bands.

Some of the early investigators recommend that the ground and diluted samples be packed into capillary tubes with an inside diameter of 0.4 to 0.6 mm and made of plastic materials (materials with amorphous patterns) or glass containing elements of only low atomic weight. The plastic materials are preferred to glass, as meaurements on Pyrex tubes with wall thickness just sufficient to permit careful handling show 40 to 50 percent absorption of the $CuK\alpha$ radiation. Longer wave lengths are absorbed to an even greater extent. Glass appears to be suitable for $MoK\alpha$ radiation; however, as will be shown later, *Mo* radiation is not desirable for use in the identification of components of mixtures.

Another mounting method recommended for long-wave-length studies on materials of low atomic weight consists in mixing the powder of the unknown with about 10 percent (by volume) of gum of tragacanth or collodion and extruding it as a rod approximately 0.5 mm in diameter.

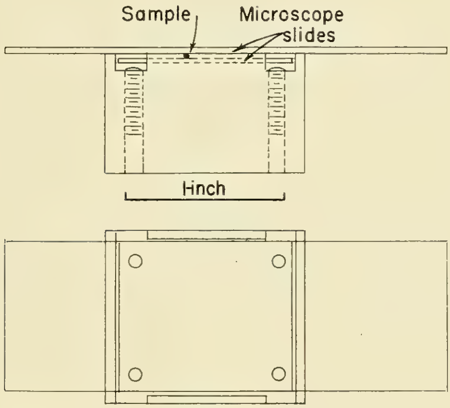


FIGURE 9-5. Jig for rolling samples to predetermined thickness threads.

An excellent method of mineral specimen preparation used by some of the most prominent workers in the field, although it is usually not described in standard texts nor recommended in the American Society for Testing Materials procedures (E43-42T, 1942), consists in mixing the powder of the unknown with a minimum of DuPont household Duco cement (or other plastic cements such as ethylcellulose in toluene) and then rolling the plastic mass between two microscope slides to form a thin rod of the desired thickness. Thickness can be carefully controlled by inserting the microscope slides in a jig which holds them a fixed, predetermined distance apart (fig. 9-5). The cement acts as binder and diluent, and if kept to a minimum generally will not affect the background of the diffraction pattern.

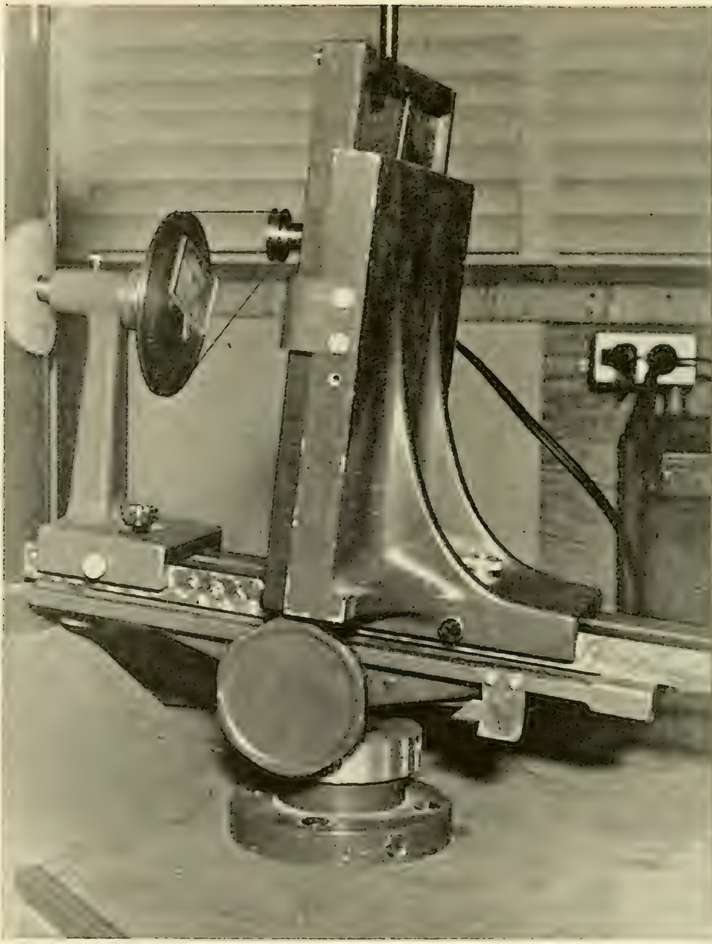


FIGURE 9-6. Flat-film camera modified to study thin sections of minerals.

Platy or fibrous crystals may become oriented in the cement during rolling of the rod. The orientation changes the circular lines of the pattern to arcs, especially the lines formed at a small angle to the beam. On film patterns orientation effects usually do not cause any difficulty where qualitative identification is the objective, so long as the film is wide enough to include all orientation arcs. On the other hand, these effects frequently are advantageous in that they give some idea concerning the orientation of the crystallographic planes producing these arcs. Moreover, because the orientation arcs are darker than would be the equivalent complete circular line, lower percentages of platy or fibrous minerals can be detected in mixtures than would otherwise be observed.

Furthermore, use of the Duco cement permits preparation of a thinner sample than would the recommended capillaries and consequently makes it possible to obtain a pattern of narrow, sharp lines with maximum resolution. With this type of sample mounting, several lines are frequently obtained at the average position of a single broad line reported in the literature.

Other methods, such as affixing the powder to strings, hair, wire, and glass rods, have been suggested also (E43-42T, 1942). These mounts commonly produce abnormal effects and do not appear desirable because of the difficulties involved in obtaining representative samples and the large amount of foreign material (the rod and binder) included in the sample. With glass rods, double lines frequently are obtained in the pattern, a condition that is very undesirable, especially in analysis of mixtures.

If only a very limited amount of material is available, a small lump 0.1 to 0.2 mm in diameter can be mounted with mucilage or Duco cement on the end of a very thin glass rod. For very fine-grained materials in which the particles are randomly distributed, a powder diffraction pattern is obtained. If the particles are not arranged randomly, the materials first should be crushed with a microspatula and the powder worked into a tiny ball with a binder. Such samples require no more than a few micrograms of material and produce satisfactory patterns at approximately double the usual exposure time.

Flat-film cameras (fig. 9-6) can readily be modified to study materials in petrographic thin sections that are not identifiable by microscopic methods. The area on which the pattern is obtained is approximately 0.005 inch in diameter, or about twice the thickness of an average sheet of paper. For this procedure the slide is warmed to soften the mounting medium, and the thin section slid over so that the region to be studied projects over the edge of the glass slide. The cover glass is retracted at the same time. The specimen is mounted in the camera under the petrographic microscope to insure centering of the selected area in the beam. The sample is rotated during the exposure to produce smooth, uniform lines in the pattern. After the pattern has been recorded, the slide is again warmed, and the thin section returned to its original position and covered with the original cover glass.

At present, reliable methods for mounting powder samples for studies with the Geiger-counter apparatus seem to be lacking. Carl (1947) has described a method which he found to yield satsifactory quantitative accuracy. Whatever method is selected, it should be remembered that different materials pack differently into the holder, and the operator should first check his technique on a series of synthetic samples of known composition before attempting to use it quantitatively or on unknown specimens.

TYPE OF FILM AND ITS POSITION IN CAMERA

As indicated in Figure 9-7 diffraction lines (rings) can be produced over the entire region from 0° to approximately 175° of the 2θ angle. Some materials such as metals and inorganic compounds produce patterns ranging over the entire region from 0° to 175°, whereas other materials as organic compounds produce their entire visible pattern at relatively small angles. Certain sections of the region from 0° to 175° may be selected for detailed study, as for example in back-reflection work or studies where extreme accuracy is involved, when the region from 130° to 175° is used. Consequently, the type of camera and film selected depends upon the objective of the investigation.

Most, if not all, X-ray film emulsions presently available were developed primarily for radiographic work and consequently have a rather high degree of contrast to reveal relatively small differences in absorption by the materials studied. For diffraction work, especially for studying mixtures, a film showing a straight-line function with a moderate slope over a considerable range, when the line density is plotted against exposure, is desirable. Thus the choice of film rests on a number of conditions. For rapid and only approximate identi-

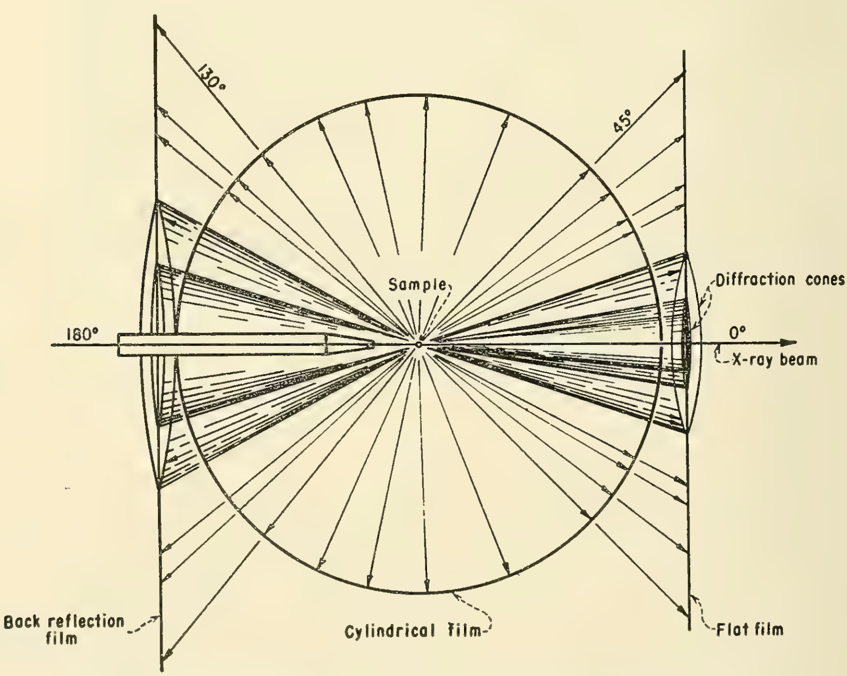


FIGURE 9-7. Film positions in various cameras used for powder studies.

fications, the fast films are preferred, whereas slower films are used if all possible information is to be gleaned from the pattern. Films as a rule are duplitized, that is, they have emulsions on both sides. To a slight extent, the double emulsion causes diffuseness in the lines, but rarely sufficiently to justify use of single-layer-emulsion film. All films should be developed according to the time, temperature, and processing conditions recommended by the manufacturer.

Intensifying screens have been used for cutting down exposure time, but this practice is not recommended for mixtures of minerals because the screens broaden the pattern lines and thereby decrease resolution.

The use of the $K\alpha$ doublet radiation from molybdenum has been recommended for chemical analysis by the X-ray-diffraction or Hanawalt method (E43-42T, 1924). This radiation is very good for the identification of metals or alloys which usually have very simple patterns but does not appear to be of much value for complex mixtures such as rocks and soils, for which the patterns should be spread out as much as possible to prevent superposition of lines from the different patterns of the constituents in the mixture. Reference to Table 9-I which shows the angular range of corresponding patterns produced by the common target materials available as compared to the full pattern range (170°) for chromium $K\alpha$ radiation, should remove any doubt concerning the foregoing statement. The results given in this table should enable the operator to choose the radiation for his particular needs. Where the operator is restricted to a single type of radiation, the $K\alpha$ of copper is chosen almost invariably because it favorably combines sample penetration with a reasonably expanded pattern of good quality.

TABLE 9-I

Angular Range of Corresponding Patterns Produced By Common Target Materials

Radiation	λ	*Angular Position of line with d = 1.1497 Å.*
Cr	2.29092	170° 0′
Fe	1.93728	114°48′
Co	1.79021	102°10′
Cu	1.54178	84°18′
Mo	0.71069	36° 0′

Since the K X-ray spectrum always contains characteristic radiation of several wave lengths, suitable filters (Clark, 1955; Bunn, 1946) or a crystal monochromator should be employed to produce reasonably monochomatic radiation and thus avoid superposition of lines from a second pattern derived from $K\beta$ radiation. In patterns of pure substances or very simple mixtures, the position of K_β lines can be calculated and the lines disregarded in the interpretation of the data. However, the K_β radiation should be removed when making patterns of mixtures, as such patterns are always very complex and the presence of K_β lines serves only to cause errors and confusion.

MEASUREMENT OF LINES IN PATTERN AND CONVERSION TO d VALUES

The X-ray pattern usually must be measured and the data used to determine interplanar spacings or the unit-cell dimensions. Consequently, all precautions must be taken in the processing of the film to avoid film shrinkage or to reduce it to negligible amounts. Film shrinkage can usually be kept to a minimum and often to the point where it is negligible by rigidly following a processing procedure which keeps all times in the procedure to the minimum required. Film shrinkage has been found to increase with washing time, especially if prolonged and the shrinkage is not uniform throughout the entire film (Claassen, 1946). Developing procedures can be checked for film shrinkage by exposing, or marking, on the film fixed lengths before processing. Correction for shrinkage is also frequently made through the use of an internal standard such as NaCl the line positions of which are accurately known, the pattern for NaCl being superposed directly on the pattern of the unknown.

A number of measuring devices are offered by manufacturers of X-ray apparatus with which either the diameters or radii of the powder rings can be rapidly and accurately measured in units of length, usually centimeters. These devices could be calibrated directly in *KX* or *Å, units* (*Å.* = 1.00202 *KX* units), but calibration in this way restricts their use to a single type of camera with a fixed radius. Consequently, the measurements in centimeters must be converted into interplanar spacings or the unit-cell dimensions by calculation or calibration curves indicating ring diameters or radii (in centimeters or millimeters) as a function of interplanar spacing (in angstrom units). For rapid and approximate measurements, a direct-reading scale on transparent plastic can be prepared from calculated or plotted data, interplanar distances equivalent to each ring being read directly when the scale is superimposed on the pattern.

If single-crystal-rotation patterns taken perpendicular to each of the three crystallographic axes are available, one dimension of the unit cell can be calculated from each of the three patterns. For cylindrical patterns the angle u_n is caculated from the tangent function of the distance measured on the pattern between the *0* and *nth* layer line and the film radius. For flat patterns it is calculated from the distance measured between the *0* layer and the apex of the *nth*-layer-line hyperbola and the sample-to-film distance (fig. 9-8). This value is then substituted in the equation:

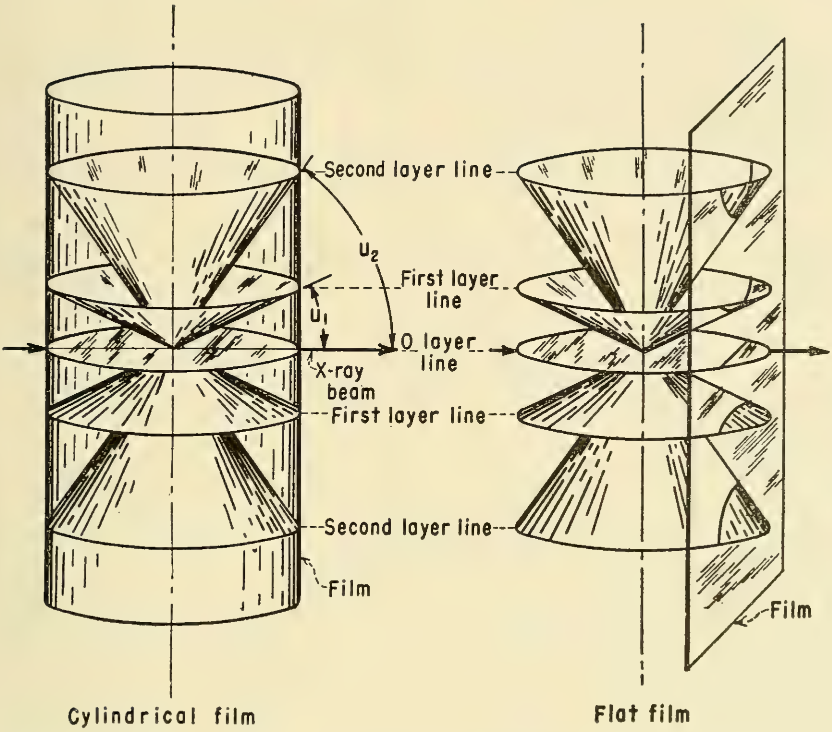


FIGURE 9-8. Schematic diagram of single-crystal layer-line positions in cylindrical- and flat-film cameras.

$$I = \frac{n\ \lambda}{sin\ u_n}$$

to obtain the identity period, *I*, or the distance between planes from one equivalent point to the next along the axis of rotation (Friedman, 1945). On the other hand, if the diffraction data were obtained by the powder method, a technique considerably simpler than the single-crystal rotation method, the procedures of measurement and calculation are different. The diameters (or radii) of all lines in the pattern are measured and recorded in centimeters or millimeters. If the X-ray pattern is recorded on flat film, the Bragg angle is obtained from the tangent relationship, namely,

$$tan\ 2\theta = \frac{line\ radius}{sample\ to\ film\ distance}$$

With the Bragg angle θ known, the interplanar distances, *d*, can then be readily calculated by means of Bragg's law,

$$d = \frac{n\lambda}{2 \sin \theta}$$

with the powder pattern recorded on cylindrical film the Bragg angle in degrees is obtained from the relationship,

$$2\theta = \left(\frac{a}{R}\right)\frac{360}{2\pi} \text{ or } \theta = \frac{90a}{\pi R}$$

where a is the line radius on the film in millimeters and R is the film radius (camera radius) in millimeters. Substituting this value of θ in Bragg's law we obtain (Clark, 1955)

$$d = \frac{n\lambda}{2 \sin\left(\frac{90a}{\pi R}\right)}$$

In some commercial cameras available today, the diameters have been so chosen that one millimeter film distance is equivalent to 1° or 2°, θ angle.

In addition to this calculation, the relative line intensities must be evaluated. The intensities are expressed in some system, for example as V.V.S. to V.V.W. (very, very strong through various gradations to very, very weak), or on a numerical basis ranging from 10 to 1 or 1 to 0.01. Visual approximation of intensity is sufficient, as a trained operator usually can see all the details in a pattern that can be detected with a densitometer. Relative intensities of lines in a well-exposed pattern are different from those in an underexposed pattern. Differences in exposures not only result from changes in exposure time from specimen to specimen, but also occur within a single pattern representing a mixture containing both large and small proportions of the several ingredients (Hellman, 1944). If a particular constituent is to be determined, the writer has found it advisable to prepare a series of underexposed patterns of the constituent in pure form with exposure times of 1 percent, 2.5 percent, 5 percent, etc., of that used in obtaining the pattern of the mixture. This procedure will demonstrate why rather strong lines of the patterns of minor constituents frequently cannot be found in the pattern of the mixture. Such a series of patterns can also be used by semiquantitative estimation (see page 173).

IDENTIFICATION OF MINERALS AND COMPONENTS OF MIXTURES

If X-ray diffraction data have been obtained from single-crystal rotation patterns and unit-cell dimensions calculated, the identity of the compound usually can be determined, directly by means of suitable tables (Donnay, 1954).

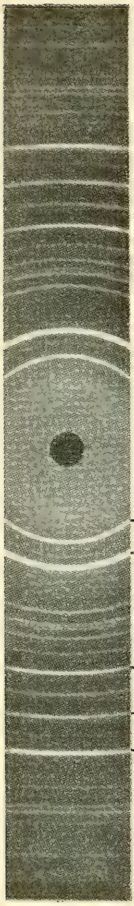
If the X-ray diffraction data were obtained from powder patterns, the process of qualitative and semiquantitative identification is considerably simpler than if only single-crystal rotation patterns were available. For identification of a specimen from a powder-diffraction pattern, the radii, or diameters, of all lines in the pattern are measured, and the interplanar spacings calculated. The details of the procedure to be followed depend on the nature of the unknown and on the amount of other data available, such as optical and physical properties and chemical analyses.

If the unknown represents a pure compound or a mixture composed essentially of one constituent with only minor amounts of other ingredients and nothing is known concerning the identity of the compound or the principal ingredient, the Hanawalt method of identification is used.

The Hanawalt method, recommended by the American Society for Testing Materials, is based upon a card-file index system catalogued according to the three strongest lines in the pattern (A.S.T.M., E43-42T, 1942). After the pattern of the unknown has been measured, converted into interplanar spacings, the intensity of the lines estimated, and at least the three strongest lines (more if the three strongest lines are not outstanding) identified, the group of cards representing materials for which the strongest line corresponds to the same interplanar spacing as does the strongest line in the pattern is selected from the index. The subgroup for which the second-most-intense line corresponds to the same interplanar spacing as does the second-strongest line in the pattern of the unknown is then examined for correspondence between the third line of the cards and the third-strongest line in the pattern. Finally, the entire pattern of the unknown is checked against the pattern selected from the card index. This procedure is illustrated in Figure 9-9. However, because of differences between the techniques used in obtaining the data for the card index and that used by the operator in obtaining the pattern of the unknown, or because of variations found in the patterns of some types of materials (to be discussed later), the operator should regard correspondence within $\pm$ 0.05 Å as a satisfactory match for interplanar spacing in comparing his patterns with those recorded in the index. This same possible variation should be allowed in selecting the groups of cards for comparison.

The A.S.T.M. data cards described above are available in three different types, namely, plain cards, punch system cards, and I.B.M. machine cards.

Should the foregoing procedure be unsuccessful or if the specimen to be identified is known to be a mixture of several ingredients all in only small or moderate concentration, a somewhat different method of identification must be used. In mixtures, each of the three strongest lines may belong to patterns of different constituents so that the above procedure could not be used. For relatively simple mixtures, the procedure above may work if more of the strongest lines (10 or 12) are used in searching the card index. In general, however,



Radius in cm.	KX units	Estimated relative intensity	Order of intensity
1.82	4.25	.30	2
~~2.09~~	~~3.71~~	~~.05~~--Beta of 3.35 KX line	
2.33	3.35	1.00	1
3.20	2.45	.15	
3.44	2.28	.13	
3.52	2.23	.07	
3.71	2.12	.10	
4.00	1.97	.07	
4.38	1.818	.25	3
4.80	1.670	.09	
4.84	1.657	---	
5.24	1.538	.20	4
5.59	1.450	.01	
5.95	1.373	.25	3
6.42	1.286	.03	
6.62	1.253	.05	
6.79	1.226	.02	
6.99	1.196	.07	
7.11	1.180	.09	
7.33	1.150	.03	
7.94	1.080	.05	
8.28	1.044	.03	
8.41	1.033	.02	
8.63	1.013	.02	

1612

d	3.35	4.25	1.82
I/I_1	1.00	0.25	0.25
I	100	25	25

SiO_2 (α- quartz)

Z=

a_0= b_0= c_0=

A= C=

D =

n = = =

d in Å λ=.708	I/I_1	d in Å λ=.708	I/I_1
4.25	0.25	1.299	0.04
3.35	1.00	1.256	0.03
2.45	0.15	1.228	0.03
2.29	0.10	1.200	0.06
2.23	0.06	1.180	0.08
2.12	0.09	1.155	0.01
1.97	0.08	1.080	0.04
1.82	0.25	1.048	0.02
1.66	0.08	1.035	0.01
1.54	0.20	1.015	0.01
1.450	0.02		
1.375	0.25		H

FIGURE 9-9. Illustration of the use of the card-index method of identifying an unknown.

only the strongest line of the pattern can be used as a guide for selecting the group of cards for comparison. All of the lines on each card of the selected group are compared with the pattern of the unknown; bearing in mind, of course, that at least all the strongest lines must be found in the pattern of the unknown, with proper relative intensity. Checking of only a few lines on a card is usually sufficient to indicate whether or not agreement exists. When a card identifies part of the pattern of the mixture, the lines belonging to the pattern of the identified constituent are marked (on the pattern or a corresponding tabulation of data). The procedure is now repeated for the remainder of the pattern, again starting with the strongest remaining line. In this way all the constituents of the mixture can be identified, provided their patterns are catalogued in the index, when fluorescent scattering is small (recognized by light background in the X-ray pattern). The relative amounts of the ingredients present are deduced from the relative intensities of the lines in the pattern, as compared to the intensities of the lines in the pattern of the pure constituents, the exposure times, of course, being the same for all patterns. A series of underexposed patterns (1, 2½, 5, etc., percent of the total exposure time) of the pure constituent in question will be of considerable help in estimating these intensities.

If the absolute proportion of each compound in the mixture is to be determined, a synthetic specimen must be prepared from the identified pure materials in such proportions that the synthetic mixture yields a pattern matching in spacing and intensity all the lines of the original pattern, when both patterns are prepared under identical conditions of exposure and processing. If line shifts, fading of the pattern in general with increasing values of the 2θ angle, or other differences are observed in the patterns, irregularities of composition, such as solid solutions, are indicated and the compound composition of the specimen must be determined by calculation from a chemical analysis. The chemical analysis frequently is best accomplished by means of standard spectrographic procedures. For a thorough study of mixtures of silicates, the methods of X-ray diffraction analysis (Clark, 1955; Ballard, 1946 and 1940) are practically indispensable. These methods reveal the various chemical combinations in which the silicon exists, whereas chemical or spectrographic methods alone yield only the total amount of silicon in the unknown, giving no clue as to its mode of combination.

In the original and first supplementary sets of cards, the values of the *d*-spacings corresponding to the three strongest lines, together with their corresponding relative intensities, appear in the upper left-hand corner of each card (fig. 9-9). There are three cards in the file for each diffraction pattern; the first card has the strongest line of the pattern at the extreme left and also contains the complete pattern data and some crystallographic data where available. The second card has the second strongest line in this position, and the third has the third strongest line in this position. The cards with the second and third strongest lines at the extreme left position are only "follow" cards and do not contain any data other than the *d*-spacings corresponding to the three strongest lines. The cards are filed in straight numerical order.

The revised original and supplementary sets include only one card for each pattern, so as to reduce the required number of cards. A book entitled

Alphabetical and Grouped Numerical Index of X-ray Diffraction Data (Special Technical Publication No. 48-E, A.S.T.M.) is now furnished with these data cards. This book lists each pattern in three different places; i.e., as if each of the three strongest lines were actually the most intense line in the pattern. Pattern searching by means of this book greatly reduces the labor involved. These cards also include the data for the *d*-spacings corresponding to the three strongest lines of the pattern listed in decreasing order of intensity in the upper left corner of the card. The data for the largest spacing of the pattern are given to the right of the data for the three strongest lines. Wherever available, additional data consisting of the data for the X-ray setup, crystallographic information, optical information, and information concerning the source, preparation, heat treatment, etc., of the sample are given. In addition, the card contains the formulas (chemical and structural for organic compounds), name, and complete pattern data. The cards are arranged into small Hanawalt groups of convenient size for values of the strongest line, and each group is arranged in numerical sequence according to the values of the second strongest line. This difference between the old and the revised-card indices will, of course, alter the above-described procedure somewhat when the revised index is used. With the revised index, the search of the diffraction-data file starts with two lines chosen from the unknown pattern as the strongest and second strongest. If this choice does not locate a corresponding X-ray pattern, it is necessary to reverse the order of the lines and search again.

It may even be necessary to try various other combinations of strong lines in the pattern before the identification can be made. For those who wish to continue the original method of searching the data file, the Society offers additional sets of the revised cards at reduced prices.

When considerable investigation is being carried out in a limited field, or if sufficient optical or other data are available so that the possible compounds in unidentified specimens are relatively small, it frequently is advantageous to build up a file of patterns of standard materials. These patterns can then be used for identifying unknowns by direct comparison with their patterns. Figure 9-10 illustrates this method. However, it is to be strongly emphasized that extreme caution must be observed in selecting the materials for these standard patterns. Errors in identification are found frequently even for specimens obtained from established museum and private mineral collections.

Direct comparison of patterns, when used together with the Hanawalt method described above, but using the standard patterns in place of the cards is the most satisfactory for identification of materials, both in accuracy and time saved in the anlysis. Occasionally, the Hanawalt method fails for mixtures because several strong lines of different ingredients fall in juxtaposition on the pattern and consequently are considered as a single broad line in the interpre-

1
2

FIGURE 9-10. Direct comparison of pattern of unknown with a standard pattern: 1—Pattern of unknown mixture. 2—Standard pattern of quartz.

tation of the data, thus considerably displacing the position of the line in question. If the probable constitution of the mixture can be surmised, direct comparison with standard patterns will immediately disclose such situations, and errors and time-consuming labor are avoided.

Occasionally unit-cell data are available in the literature when powder data are lacking (Donnay, 1954). Unit-cell data for a known material can be used to establish the identity of an unknown material from which a powder-diffraction pattern has been obtained. This method is practicable only if some clue suggests the identity of the unknown, and the number of known materials to be compared with the unknown is small. The comparison of the unit-cell data with the powder-diffraction data is accomplished by application of the reciprocal-lattice concept. A complete explanation of this concept is, of course, beyond the scope of this chapter and the reader is referred to other sources (Clark, 1955; Davey 1934; Bunn, 1946). However, it can be shown that the relationship between the true lattice (real space) and the reciprocal lattice (reciprocal space) can be expressed by the equation

$$d = \frac{R\lambda}{d^*}$$

where d is the interplanar distance in the true lattice, d^* the interplanar distance in the reciprocal lattice, λ the wave length of the radiation used, and R a constant called the "magnification factor" applied to convert the dimensions in reciprocal space to such a magnitude that the reciprocal lattice or net can be plotted easily in cm-units. If the unit-cell dimensions are not much over 10 Å, the value $R = 10$ will produce a reciprocal net of convenient dimensions. If the unit cell has dimensions between 10 and 30 Å, a value of $R = 20$ should be chosen. Briefly, the procedure is the following: the a, b, and c dimensions of the unit cell are converted into reciprocal-cell dimensions by means of the equation above and the resulting three-dimensional net plotted in one plane by folding the vertical planes down into the horizontal plane (fig. 9-11). Thereupon, the experimentally determined powder-diffraction data are also converted into reciprocal dimensions by the same equation and the results (rings representing the ends of reciprocal space vectors free to turn about the origin) are superimposed on the reciprocal net of the unit cell. If the unit cell fits the experimentally determined powder-diffraction data, there will be a net intersection at the end of each vector; i.e., the rings derived from the powder data will all pass through one or more intersections of the three-dimensional reciprocal unit-cell net.

A mixture of minerals which are frequently difficult to differentiate by optical examination, especially when examined in the form of a rather fine powder, has been chosen to illustrate this method. Owing to the nature of these

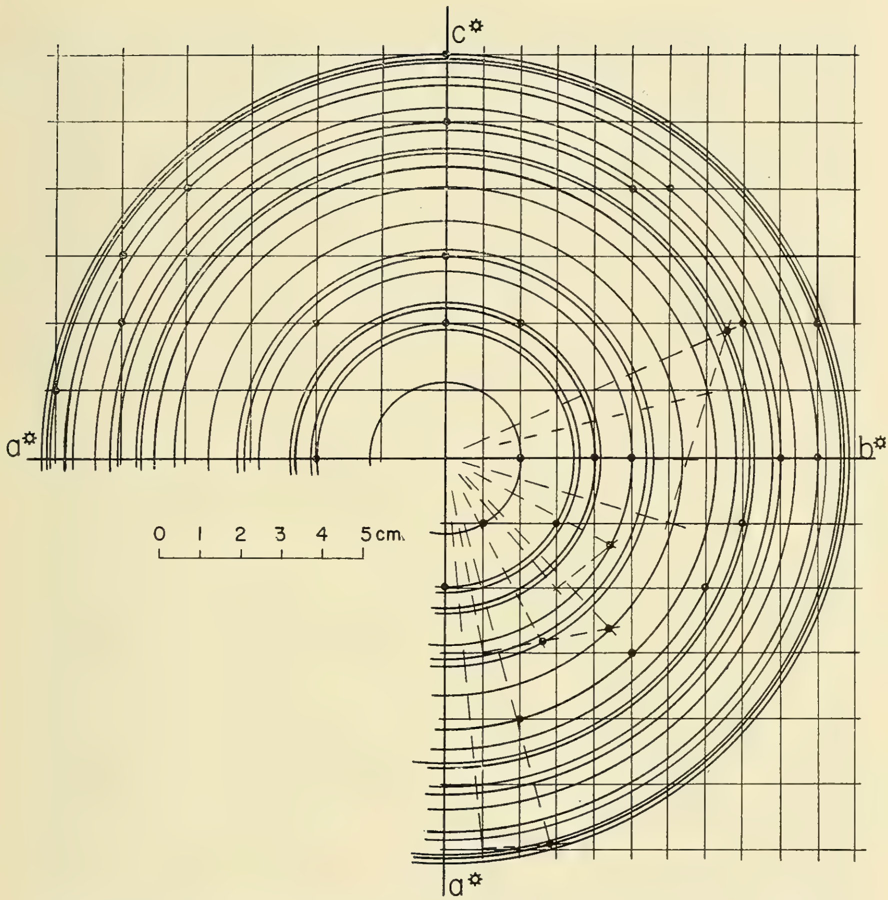


FIGURE 9-11. Comparison of powder data of unknown with possible unit-cell data.

minerals, the mixture appeared to be a single homogeneous substance. A diffraction-powder pattern, however, definitely showed it to be a mixture. With the regular powder methods described above, one constituent could readily be identified as quartz from these powder data. This identification is further verified by direct comparison with a standard quartz pattern (fig. 9-10).

Assuming that powder data were not available for the other constituent of the mixture, it would then be impossible to identify this constituent with the aid of the card index. However, if now through more thorough optical examination, further data can be obtained to limit the number of possible compounds to be checked to a reasonable number, identification will still be possible if suitable unit-cell data are available. In this case, this would involve careful checking of the refractive indices, obtaining the birefringence, and, if possible, such information as would enable one to classify the constituent as isotropic, uniaxial, or biaxial. Now further checking of the list of possible constituents obtained by the above procedure against the list for which powder data are available will readily reduce the possibilities so that it will become feasible to apply the reciprocal-lattice method shown in Figure 9-11.

All unidentified lines of the pattern of the unknown are converted to lines having reciprocal radii by means of the above equation and the resulting circles drawn on transparent paper or plastic. The unit-cell dimensions of the possible constituents are then converted to reciprocal dimensions, and these reciprocal three-dimensional nets are drawn on separate sheets of paper. For Figure 9-11 the unit-cell dimensions are those of cordierite: namely $a = 17.1$ Å, $b = 9.78$ Å, $c = 9.33$ Å, in the orthorhombic crystal system. The experimental data are then superimposed on these various possible nets and the experimental lines (rings) checked for agreement with the net intersections. If a reasonable number of lines show agreement, then any lines not identified by the net intersections directly as (h00), (0k0), (00l), (hk0), (h0l), and (0kl) are checked for (hkl) agreement (dotted triangles in Figure 9-11 represent coincidence of (hkl) net intersections with experimental data lines). Coincidence of one or more net intersections with every experimental powder-data line identifies the second constituent in the mixture as cordierite.

EMISSION X-RAY SPECTROGRAPHIC ANALYSIS

Within recent years emission X-ray spectrographic analysis has been developed to the extent that now it is capable of analyzing for all elements with atomic number greater than 11. With suitable standards such analyses can be made in considerably less time than is normally required for wet methods. The accuracy of these analyses compares favorably with that of the wet methods and the range of detection for most elements extends from .01 or .02 percent to 100 percent. Since even a preliminary discussion of this method is beyond the scope of this chapter, the reader is referred to the standard texts and periodicals that described the various phases of the method (Klug, 1954; A.S.T.M., S.T.P. 157, 1953; Cullity, 1956; The Norelco Reporter v. I, II, III, etc., 1953).

APPLICATIONS

The value of X-ray diffraction methods, particularly as a research tool, need no longer be questioned. A brief examination of the technical journals will quickly verify this statement. Naturally, the greatest effectiveness is derived when X-ray data are

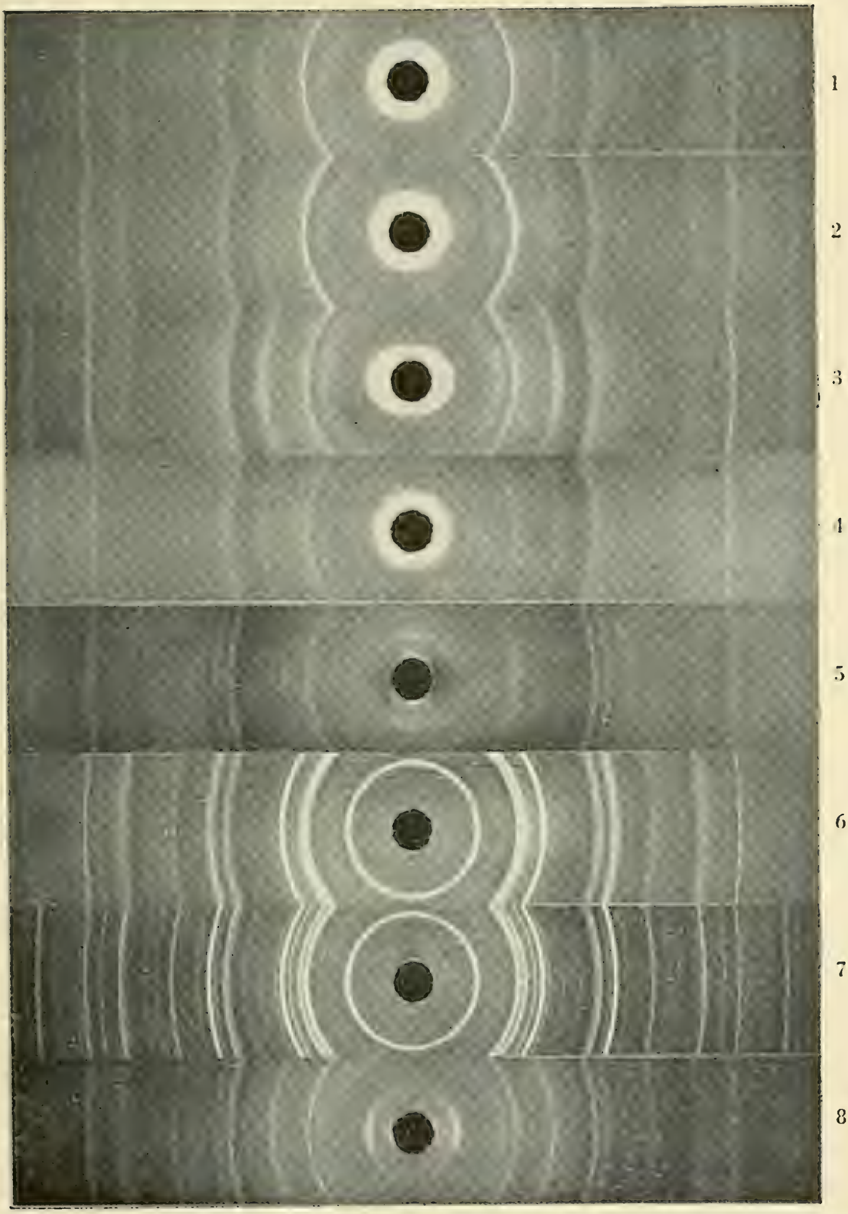


FIGURE 9-12. Typical clay patterns. 1—Wyoming bentonite (montmorillonite). 2—Beidellite. 3—Hectorite. 4—Nontronite. 5—Glauconite. 6—Kaolinite. 7—Dickite. 8—Illite.

supplemented by physical and chemical studies made by other methods; however, the method can also be used independently to great advantage in many problems. At times X-ray diffraction methods are more rapid and efficient than other methods and in some problems the answer can only be obtained by the use of X-ray procedures.

Due to their minute particle size, clay minerals are extremely difficult to identify by other methods, especially so when they occur as mixtures. Figure 9-12 shows X-ray patterns of some of the more common clay minerals. It should be observed that some members of the montmorillonite group show very definite similarity; however, with the aid of a good set of standard patterns a remarkable amount of information can be obtained from their diffraction patterns. This information can be verified and extended appreciably by the use of other methods such as differential-thermal analysis (Grim, 1942, 1947), electron microscope studies and thermal gravimetric analysis (Mielenz, 1953). The nature of the nominal 14Å line (usually the first line in the pattern from the center outward) gives considerable information about the adsorbed cations. This can be verified with patterns from a series of specimens calcined at various temperatures. Furthermore, patterns of mixed sodium and calcium adsorbed cation clays made under controlled conditions enable us to determine the relative amounts of each of the ions present from the value of d spacing (Williams, 1953). Likewise the position of the nominal 1.49Å line (060) (approximately one half inch from edges of patterns in Figure 9-12) gives considerable information concerning the nature of the ion in the octahedral position since the line shifts toward the center of the pattern as the diameter of the ion increases.

X-ray diffraction methods are likewise particularly valuable in the analyses of shales. These are frequently so fine-grained and so heterogeneous in composition that alternative methods are inadequate.

A brief description of a few of the many problems solved with X-ray diffraction will serve to give the reader some idea of how X-ray diffraction studies can be advantageously applied to problems that may be encountered in various fields.

Through X-ray diffraction studies it has been possible to learn the nature of the structure of the various clay and micaceous minerals and the close structural relationship between them. Similar studies have given us a vast amount of structural information for many other minerals. By means of X-ray diffraction studies we were able to learn the nature of the mechanism of hydration in clay minerals and some micaceous minerals which supplied us with information concerning swelling behaviors and the development of excessive pressures with moisture absorption by some types of dried clays when free swelling was restricted. This now enables us to analyze the foundation materials upon which structures, such as buildings, dams, and highways, are to be erected and thus avoid serious damage to these structures as a result of swelling pressures. Some clay-containing shales have the tendency to break down into mud upon re-wetting if they are permitted to dry out. Foundation analysis would make it possible to prevent serious damage in such cases. A closely related problem was the occurrence of laumontite in foundation rock which upon exposure to air was transformed into leonhardite. The loss of water had made the rock very soft and friable.

With X-ray diffraction methods it is possible to follow changes in soils, shales, clay minerals, minerals, etc., that occur as a result of calcination. This enables us to analyze ceramic materials and learn what optimum conditions are required to produce top-grade products rather than products of mediocre or unsatisfactory grades. Such knowledge also enables us to select suitable, or to discard unsatisfactory, raw materials and shows us which raw materials are satisfactory for specific purposes as in the production of light weight aggregate, or how unsatisfactory raw materials can be upgraded by the addition of certain substances or minerals. With such studies we can easily follow the reason for changes in behavior that result from various calcination procedures and in the past have been able to show that unsatisfactory products were the result of faulty processing equipment. Such knowledge, likewise, enabled us to predict which materials were satisfactory for the production of pozzolanic materials and gave a method for analyzing the finished products. With this knowledge we have been able to produce materials by which expansion in concrete due to alkali-aggregate reaction was reduced by 95 percent.

X-ray diffraction methods, likewise, enabled us to follow mineralogic changes due to hydrothermal alteration of rocks which produced ore bodies. Generally we found the sequence, ore body, sericite zone, kaolinite zone, montmorillonite zone, chlorite zone and unaltered rock as we moved outward from the ore body in selecting our samples. This knowledge now permits us to study ore-bearing areas through systematic sampling by means of drillcores and by means of the alteration sequence learn where suspected ore bodies should be located.

This method of investigation also is being used extensively to support stratigraphic correlations. In such studies members of formations are traced and identified from one outcrop to another.

Thus, after reviewing a number of solved problems it should become obvious that X-ray diffraction methods of analysis of geologic materials can be used in subsurface investigations to supply the geologist with information not otherwise obtainable, to furnish the petroleum engineer with precise knowledge of the composition and certain properties of reservoir rocks, and to trace mineralogic and structural changes of importance in problems of sedimentation and sedimentary petrology.

The precise identification of mineralogic composition made possible by the X-ray diffraction methods will permit the correlation of formations where other data are lacking, or may prevent erroneous correlation based on unreliable information. Identification of the kind and amount of minor constituents in apparently homogeneous, thick formations may subdivide the sequence in such a manner as to demonstrate the stratigraphic relationship to similar formations occurring elsewhere.

The analysis of reservoir rocks by X-ray diffraction may reveal details of composition otherwise overlooked. In particular, the kind and amount of interstitial clay may critically control effective porosity and permeability of formations by changes in hydration and degree of flocculation as a consequence of change in the solutions saturating the rock. Flocculation or deflocculation and hydration or dehydration of clay minerals are controlled by their mineralogy as well as by their environmental changes. Hence, the susceptibility of clay minerals to change during the water-flooding or other secondary-recovery programs can be detected by X-ray diffraction analysis of reservoir rocks.

The geologist and engineer will find that X-ray diffraction methods increase the reliability of geologic logging. The method supplements petrographic techniques of logging drill core, making possible quick and precise identification of even exceedingly fine-grained types and complex mixtures. In addition, the method can supply basic data on petrography and mineralogy necessary to interpret more completely the electric and gamma radiation logs of drill holes. Both engineers and geologists are finding that the X-ray method of analysis is a powerful tool in the identification of potentially unsound materials in foundation strata or construction materials proposed for use in dams, powerhouses, buildings, and other large engineering works.

Finally, X-ray diffraction analysis, both of geologic materials collected from outcrops in the field and from cores of the synthetic materials in the laboratory will yield detailed knowledge of processes involved in deposition, consolidation, and induration of sediments. The methods of X-ray diffraction analysis are unsurpassed in effectiveness and efficiency in the tracing of progressive changes in mineralogy and structure of materials. Application of these methods will demonstrate the process of recrystallization during consolidation and induration, such as may occur in unstable minerals like clays, and the formation of new minerals, such as feldspar, mica, and zeolites. Only when these and related processes are understood will the conditions of petroleum formation, migration, accumulation, and production be understood fully.

The versatility and adaptability of X-ray diffraction methods have justified recognition by the petroleum geologist, engineer, and chemist. For one problem the methods may afford merely a valued supplement to other techniques; for another problem the methods may be indispensable to a successful solution.

Consequently, the supervisor of subsurface investigations should be cognizant of the potentialities of the X-ray diffraction methods so that they will be used when and as required by the nature of the problems to be solved.

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Chapter 10 THERMO-LUMINESCENCE ANALYSIS

Farrington Daniels

Some crystals emit light when heated after previous exposure to X-rays or gamma rays. This thermoluminescence has been studied in this laboratory for several years (Daniels, and others, 1949; Daniels and Saunders, 1951). When the intensity of the light is plotted against the temperature, a glow curve results with a series of peaks at definite temperatures. A typical glow curve is shown in Figure 10-1. These glow curves are reproducible for a given sample, but they depend on the chemical impurities, the physical defects, and the amount of exposure to the high-energy radiation. The glow curves can be used for identification and comparison in a manner similar to that used in spectral analysis and X-ray diffraction patterns. The fact that they depend so greatly on traces of impurities and on previous treatments makes thermoluminescence analysis much less specific and precise than spectrographic analysis, but on the other hand, it provides a tool for comparing crystals of different origins and rocks of different geological histories. It should be useful in stratigraphic analyses.

Many minerals possess natural thermoluminescence and emit light when heated even without exposure to X-rays or other high-energy radiation. This thermoluminescence is usually due to the presence of a trace of uranium (about 1 part per million) in the sample which, over the millions of years since the last crystallization process, gives an accumulated effect that is detectable. Limestones, fluorites, and granites are among the rocks which exhibit this natural thermo-

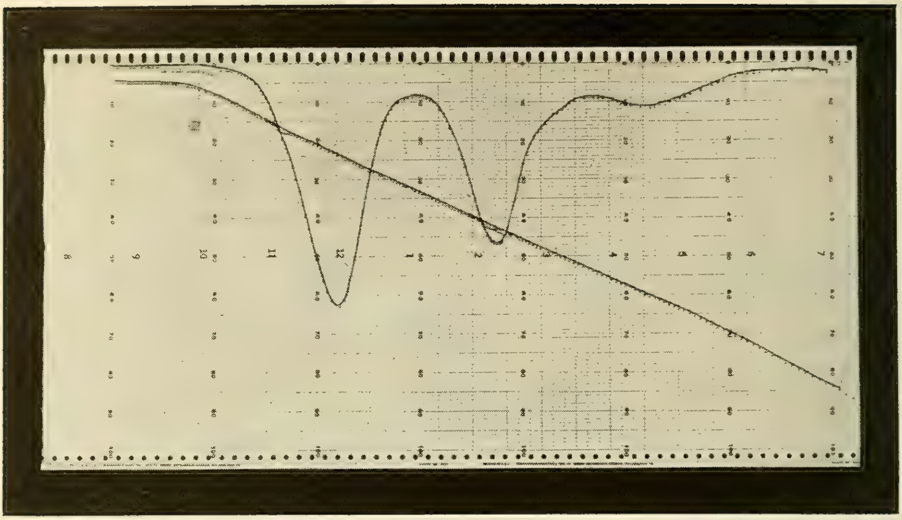

FIGURE 10-1. Typical glow curve (Escabrosa limestone).

luminescence. The light emitted is increased greatly, and additional peaks are produced in the glow curves by further exposure to X-rays. Tests on small commercial mineral collections indicated that over one half of the minerals exhibit natural thermoluminescence. Figure 10-2 indicates the extent of natural thermoluminescence found after examining hundreds of samples. The intensity ranges are arbitrary and qualitative, number 1 being barely detectable and number 4 giving sufficient light, temporarily, by which to read a newspaper, if gram quantities are used.

Many minerals and rocks, and several crystals, particularly the alkali halides, grown in the laboratory or produced commercially, show thermoluminescence after exposure to X-rays or gamma rays.

Thermoluminescence is an old phenomenon, and there are early records of the emission of light on heating certain minerals. The emission of light by glasses and minerals, previously exposed to X-rays or radioactivity, was observed soon after these radiations had been discovered. The research now going on in phosphors for fluorescent lighting and similar developments has supplied a background of knowledge which is helpful in studying thermoluminescence. The presence of minute traces of impurities is important both in phosphorescence and in thermoluminescence.

THEORY

To exhibit thermoluminescence, a substance must have an orderly structure such as exists in crystals or a semi-orderly structure as in glass. Furthermore, it must be a

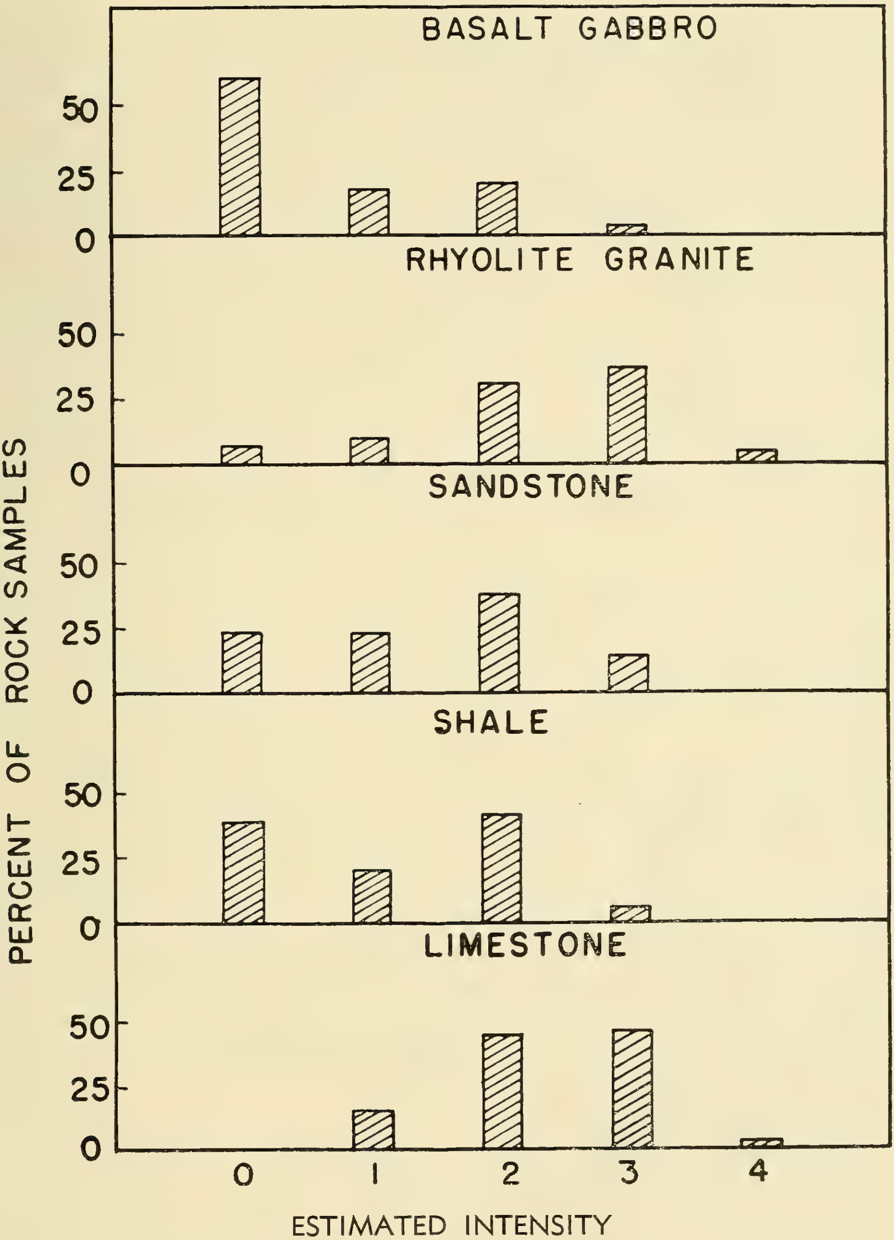

FIGURE 10-2. Distribution of natural thermoluminescence.

non-conductor or a semi-conductor for electricity, and it must be exposed to ionizing radiations which release electrons within the crystal. These high-energy ionizing radiations may be hard or soft X-rays, gamma rays, alpha rays, or beta rays. The electrons move around within the crystal, and some of them fall into traps from which they are driven out later when the temperature of the crystal is raised high enough to supply sufficient kinetic energy. There are several different kinds of electron traps: (1) imperfections and vacancies in the crystal lattice produced at the time the crystal is formed, or created later by mechanical pressure or thermal treatment; (2) statistical imperfections due to kinetic motions which increase at higher temperatures; (3) distortions produced by impurity ions of larger or smaller size than those which comprise the crystal lattice; or (4) ion dislocations or holes produced by continued exposure to radioactive bombardment.

One of the commonest types of traps is the so-called "F-center" due to a missing negative ion, such as a chloride ion in a sodium chloride crystal. An electron trapped in such a vacancy absorbs visible light and makes the crystal colored. In lithium fluoride, the ions are very small, and the frequency of the light absorption lies in the ultraviolet.

An example of the effect of foreign ions of different size is given by the addition of silver chloride to sodium chloride. When sodium chloride is fused and mixed with 1 mole percent of silver chloride and recrystallized, the gamma-ray-induced thermoluminescence is a hundred times more intense than the original sodium chloride. A crystal prepared by cooling a fused mixture of sodium chloride and potassium bromide and exposed to gamma rays gives thermoluminescence that is greater than that of the crystals of either pure salt alone.

After an electron becomes trapped in one of these several types of holes, it remains there until the temperature is raised sufficiently high to supply the kinetic energy necessary for its release. When an electron is released and it falls to another trap, or combines with an ion, at a lower energy level, it emits light. The greater the number of electrons released at one time, the greater the intensity of light, and the greater the difference in energy level involved, the shorter is the wave length of the light emitted; i.e., it is more blue or ultraviolet. The color of the emitted light reveals information concerning the nature of the traps and the impurities in the crystal, but the exact, quantitative relations have not been well-worked out yet.

EXPERIMENTAL

Qualitative observations of thermoluminescence can be made easily in the dark by simply dropping finely granulated crystals onto a plate heated just below red heat. A frying pan on an electric hot plate or kitchen stove can be used in a darkened room. The crystals or minerals should be crushed to give particles about 1 mm. in diameter. Large particles will heat through so slowly that the thermoluminescence light is too weak to observe; i.e., the number of electrons released and the number of photons emitted per second is too small to affect the eye. If the material is pulverized too finely, the light comes off in a brief flash.

In quantitative measurements, the material, in the form of a thin crystal, a thin section of a mineral, or a layer of 100- to 200-mesh size powder, is placed on a metal plate which is heated uniformly at a rate of about 25 to 50 degrees centigrade per minute, taking about 10 minutes to go from room temperature to red heat. As the temperature rises, the crystal glows for a while as electrons are released from traps of one energy level, and then the crystal becomes dark when all the electrons have been removed. As the temperature continues to rise, light may be emitted again temporarily as the electron traps of higher energy levels are emptied. Several alternating periods of light and dark may be produced before the temperature becomes high enough to give a continuous background of red light produced by black-body radiation. At this point, the experiment is discontinued because any thermoluminescent light emitted would not be detectable against the bright light emitted by the hot plate.

Figure 10-1 gives a typical thermoluminescence glow curve for a limestone (Escabrosa limestone). The straight, slanting line is a record of the temperature of the heating plate as measured with a thermocouple, whereas the glow curve with two main peaks is a record of the intensity of thermoluminescence as measured with a photomultiplier tube. These quantities are automatically plotted against time.

The apparatus used for obtaining these glow curves is shown in Figure 10-3. A silver (or iron) plate is placed over a spiral of nichrome resistance wire which is placed in a box of transite, or in a metal box filled with insulating material. A Variac or variable resistance in series with the heating coil is adjusted so as to gradually raise the temperature at a uniform rate. This is usually done by hand regulation although it is possible to have a slowly rotating, curved arm and slider arranged to turn the Variac at predetermined rates.

The sample to be measured for thermoluminescence is placed in one of the compartments on the hot plate, and the thermocouple is set in the other, or attached directly to the plate. If the sample is in the form of a powder, it is placed in a shallow circular dish with sides about 1 millimeter high. It is leveled off, giving a weight of about 1/3 gram. The light emitted increases with the amount of material heated, but after a depth of a millimeter or less is reached (depending on the fineness of the powder) further additions do not increase the light intensity because the light emitted by the lower material is scattered before it gets out. Moreover, the time lag in heating the surface material becomes appreciable if the material is too thick. In another procedure, about 50 milligrams of powder is placed on a glass plate with a drop of water containing a trace of detergent.

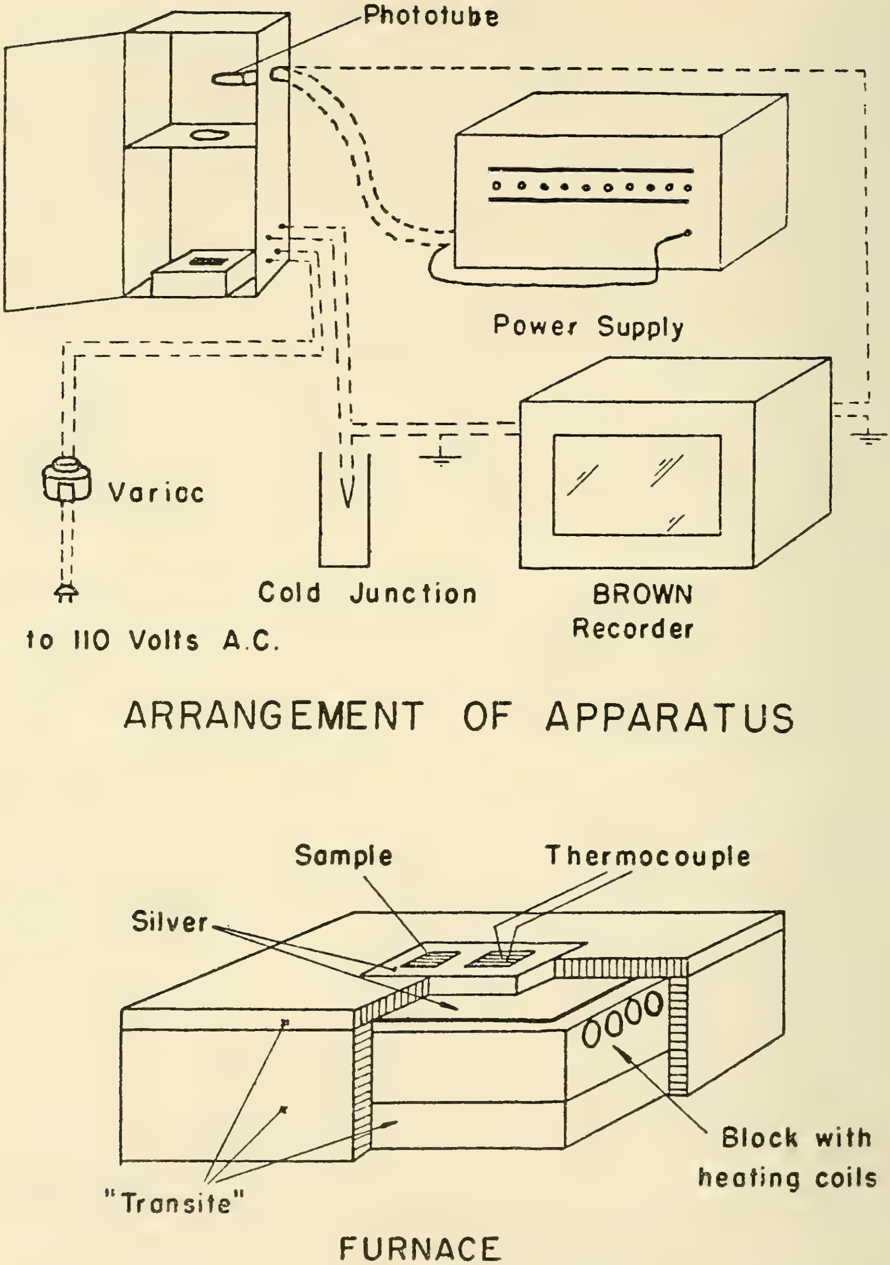

FIGURE 10-3. Glow-curve apparatus.

When the water evaporates, the crystals cling to the plate well enough for handling.

Crystals may be split in sections about 3 millimeters thick by setting the crystal on edge, pressing a razor blade against it and then tapping gently with a light hammer. Again sections may be cut from a rock with a rotating wheel and diamond powder abrasive. Sections 1 centimeter square and 3 millimeters thick are satisfactory.

Above the hot plate and sample is placed a photomultiplier tube, which consists of several photoelectric cells in series in a single evacuated tube, arranged to give great sensitivity. Different photomultiplier tubes that are available give maximum sensitivity in different parts of the spectrum. An RCA-5819 tube is satisfactory for general purposes. It may be operated either by 900 volts of radio B-batteries, or by rectifiers and electronic circuits. The heating plate and photomultiplier tube are placed in a light-tight box provided with a door. Inasmuch as sensitive photomultiplier tubes are injured for highly sensitive work by bright light, it is advisable to have a push-button switch set in the door so that whenever the door is opened for introducing or removing samples, the photomultiplier tube is disconnected.

The sensitivity of the apparatus and the constancy of the measurements are improved by placing a wide cylinder of clear quartz or glass between the sample and the phototube. It acts by internal reflection to funnel most of the light emitted by the heated sample directly to the phototube and makes possible a gas-tight separation between the upper and lower parts of the dark box so that the phototube does not become over-heated by the heating plate. For the most effective operation, at very low light intensities, the photomultiplier tube can be cooled with a stream of cold air to reduce the background current or noise level.

The current from the photomultiplier tube is proportional to the intensity of light emitted by the thermoluminescent material. It is amplified and recorded on a moving chart such as is manufactured by Leeds and Northrup, Brown-Honeywell, Esterline-Angus, Variac, or others. A single pen recorder may be used, but a double recording of both light intensity and temperature is helpful. An actual recording is shown in Figure 10-1.

A determination takes about 10 minutes, and when it cannot be continued longer because of the continuous radiation emitted by the hot plate, the heating plate and sample are removed and cooled for the next determination. If a series of determinations is being made, the heater is cooled rapidly by placing it on a cake of dry ice.

Additional glow-curve peaks can be obtained at low temperatures. The sample and heating plate are cooled with liquid air by conduction along a thick metal rod (Hecklesberg and Daniels, 1957). The irradiation of the material with X-rays or gamma rays is carried out in the cooled apparatus, and then the plate and sample are heated gradually to room temperature and above. Of course, the low-temperature thermoluminescence can never be observed when the measurements are started at room temperature because all the electrons in low-energy traps are quickly driven out at room temperature. If the irradiation takes place at room temperature, the light corresponding to low-temperature peaks is emitted as fluorescence while the radiation is being carried out. Rocks and minerals, excited by traces of uranium, will have had all the low-temperature peaks of natural thermoluminescence drained out at earth temperature.

By increasing the speed of heating, one can obtain still greater sensitivity for thermoluminescence because the intensity of light is determined by the number of electrons released and photons emitted per second. If all the electrons are released in a few seconds, the light will be much brighter for a short time than if it released slowly over a 10-minute period. A new apparatus has been developed in this laboratory in which the heating unit is simply a thin strip of nichrome sheet, which is heated very quickly by applying a low-voltage current at high amperage. The recorder, Model 127, which is manufactured by the Sanborn Company, makes a line very quickly with a heated point close to, but not touching, a specially prepared paper. A 10-inch recording is made in 10 seconds with this apparatus. The temperature is not recorded, but rough calibrations are made with materials which change colors at definite temperatures. A thermoluminescence curve obtained with this apparatus is shown in Figure 10-4.

For some geological work, the natural thermoluminescence of the material is desired. By exposing the material to intense radiation in the laboratory, it is possible to obtain much greater intensity of the thermoluminescence peaks and to introduce additional peaks, particularly the peaks near room temperature which have drained out at earth temperatures. This irradiation can be accomplished with X-rays or with gamma rays. A convenient and inexpensive source of gamma radiation may be made from cobalt metal which is then exposed to neutrons in the nuclear reactor at Oak Ridge or in other nuclear reactors of the Atomic Energy Commission. A small hollow cylinder of $cobalt^{60}$ kept in aluminum cylinders can give a uniform, high gamma radiation of several thousand roentgens inside (Saunders, and others, 1953). The source is kept in a box of lead and concrete set into a basement floor, and the samples to be irradiated are packed in a small aluminum frame and lowered into the inside of the cobalt cylinder with a pole and string and a mirror inclined to the floor at an angle of 45 degrees. The aluminum frame contains several samples of crystal plates or rock sections, or it contains several gelatin capsules containing samples of powder.

INORGANIC CRYSTALS Most of the alkali halides give excellent thermoluminescence glow curves. Schematic curves have been determined for the Li, Na, K, Rb, and Cs fluorides, chlorides, bromides, and iodides (Hecklesberg and Daniels, 1957). The larger anions give

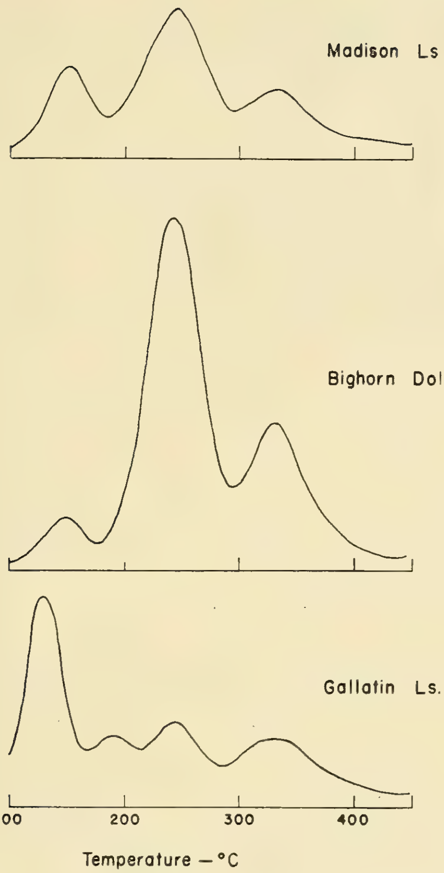

FIGURE 10-4. Typical glow curves for section in Wind River mountains, Wyoming.

thermoluminescence peaks at lower temperatures. Traces of impurities are probably a factor in the thermoluminescence although the glow curve for sodium chloride, for example, seems to be about the same for most samples, whether they are taken from reagent bottles of different companies, from highly purified laboratory preparations, or from deposits of rock salt; but they are greatly affected by added impurities of certain ions.

Many of the colorless oxides give thermoluminescence after exposure to gamma rays. The colored oxides are probably so opaque that even if electrons are trapped after exposure to gamma rays and liberated later by heating, the thermoluminescence light is absorbed in the opaque outer layers so that it cannot be observed with the eye or with a photomultiplier. Aluminum oxides have been studied in some detail (Rieke and Daniels, 1957) and the thermoluminescence glow curve depends on the extent of dehydration as determined by the temperature to which the oxide is heated. In aluminum oxide which has been heated above 1000C to remove all the water, the peaks appear to be associated with impurities of sodium. By far the brightest thermoluminescence is found in the fused and recrystallized aluminum oxide (sapphire).

The sulfates give definite thermoluminescence patterns (Moore, 1957). Sodium sulfate recrystallized many times still gives the same peaks, although there is a tendency to decrease in intensity with purification. The addition of 75 parts per million of lead introduces a prominent new thermoluminescence peak at a higher temperature. The speed of dehydration of the $Na_2SO_4 \cdot 10H_2O$ affects the glow curves. Rapid dehydration with heating gives more thermoluminescence peaks and higher intensities than long, slow dehydration at room temperatures.

Many common inorganic chemicals do not give gamma-radiation-induced thermoluminescence, but many others do. In general, thermoluminescence is most likely to be exhibited by brittle, transparent crystals having low atomic weights, occurring in simple crystal forms, and containing some impurities. An examination of over fifty inorganic crystals leads to the following generalizations (Rieke, 1957).

(1) High thermoluminescence efficiences are often obtained with fluorides, chlorides, carbonates, sulfates, oxides, and silicates, and the cations of Li, Na, K, Mg, Ca, Sr, and Al.

(2) Intermediate thermoluminescence is given by phosphates, bromides, iodides, and the cations of Pb, Cd, and Ba.

(3) Low-efficiency thermoluminescence is obtained from chromates, persulfates, ferricyanides, permanganates, nitrates, and the cations of Cr, Fe, Mn, Co, Ni, Cu, Ag, and NH_4.

LIMESTONES

Practically all limestones exhibit natural thermoluminescence and give a yellow or white light. Some limestones and dolomites give an orange light. The colors of the light are probably determined by impurities such as manganese and magnesium.

The temperatures of thermoluminescence peaks and the general pattern of glow curves vary greatly with the limestone deposit, the chemical impurities, and previous geological history. Glow curves are given in Figures 10-4 and 10-5 for different types of limestones. Many limestones have three peaks or maxima in the glow curves.

The low-temperature peaks can be annealed out without affecting the high-temperature peaks if the annealing temperature is kept low enough, as indicated in Figure 10-6. At earth temperatures, the electrons, which are trapped in imper-

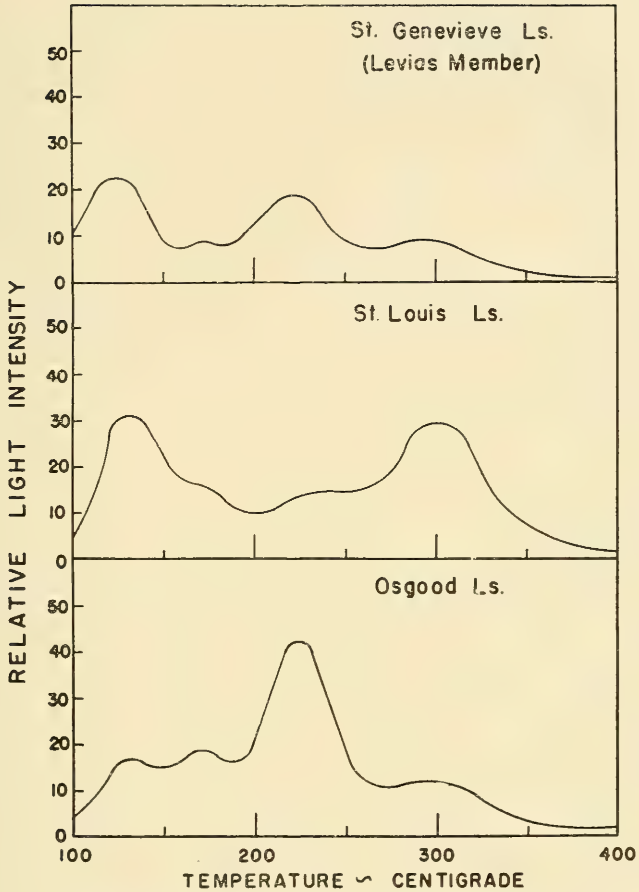

FIGURE 10-5. Glow curves of typical limestones.

fections or impurity holes of low energy levels, can escape; therefore, the low-temperature peaks do not show up. When exposed to high intensity gamma radiation, however, these traps become filled much faster than they can be emptied by thermal energy, and new low-temperature peaks are produced as shown in Figure 10-7.

An extensive study has been made of the thermoluminescence of calcium carbonates precipitated in the laboratory (Zeller and Wray, 1956). Some of the peaks are associated with impurities such as manganese and strontium, as shown in Figure 10-8. Unless the impurity ions are incorporated into the crystal lattice, they cannot act as electron traps to provide thermoluminescence peaks. The pH of the solution and the concentration of the impurities is an important factor in

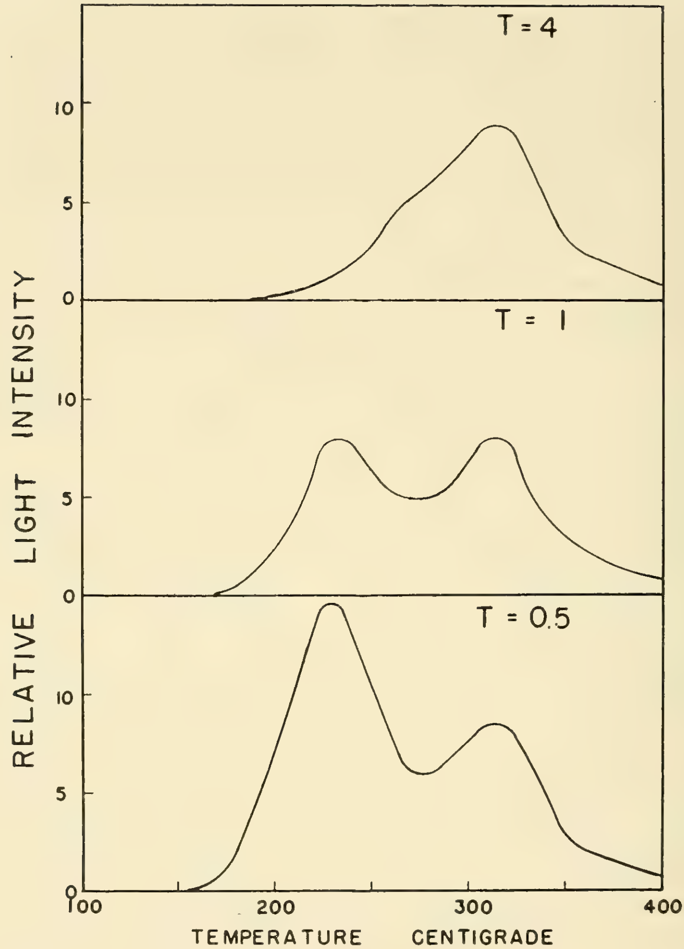

FIGURE 10-6. Effect of fractional annealing on thermoluminescence. Glow curves of Niagrara limestone. Samples heated at 175° C for T hours before being run.

the inclusion of impurities which may affect thermoluminescence. For example, in a solution from which calcium carbonate is being precipitated by the addition of sodium carbonate, any iron or manganese impurities will be precipitated with the first calcium carbonate to come down at about a pH of 6.5. As more carbonate is added and the pH is increased to about 8, strontium and barium will precipitate; and above a pH of 9, magnesium will precipitate.

The presence of strontium under properly controlled conditions of temperature and time leads to the precipitation of aragonite which changes over to cal-

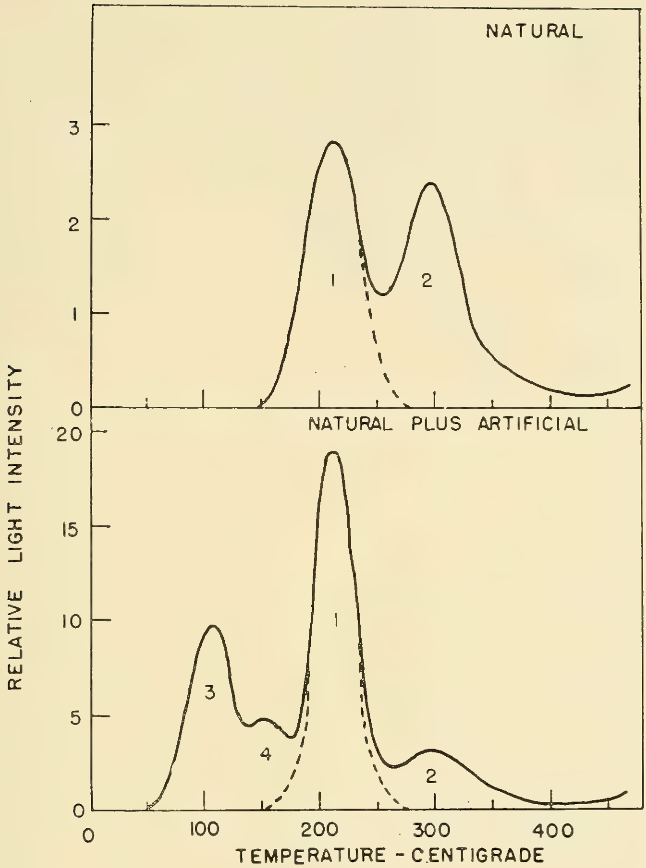

FIGURE 10-7. Increase in thermoluminescence produced by exposure to gamma radiation. Glow curves for Escabrosa limestone.

cite in solution at a rate which can be controlled under laboratory conditions (Wray and Daniels, 1957). The change-over from aragonite to calcite is a factor in the thermoluminescence glow curve.

The structure of limestones varies greatly. If the rock contains small fossils, these will have different impurity concentrations than the imbedding crystal structures and give rise to different thermoluminescence intensities.

Dolomites give a different thermoluminescence glow curve than do mixtures of $CaCO_3$ and $MgCO_3$. This difference may be due to differences in the crystal lattice, or it may be due to differences in the impurities that are taken into the dolomite and calcite crystals.

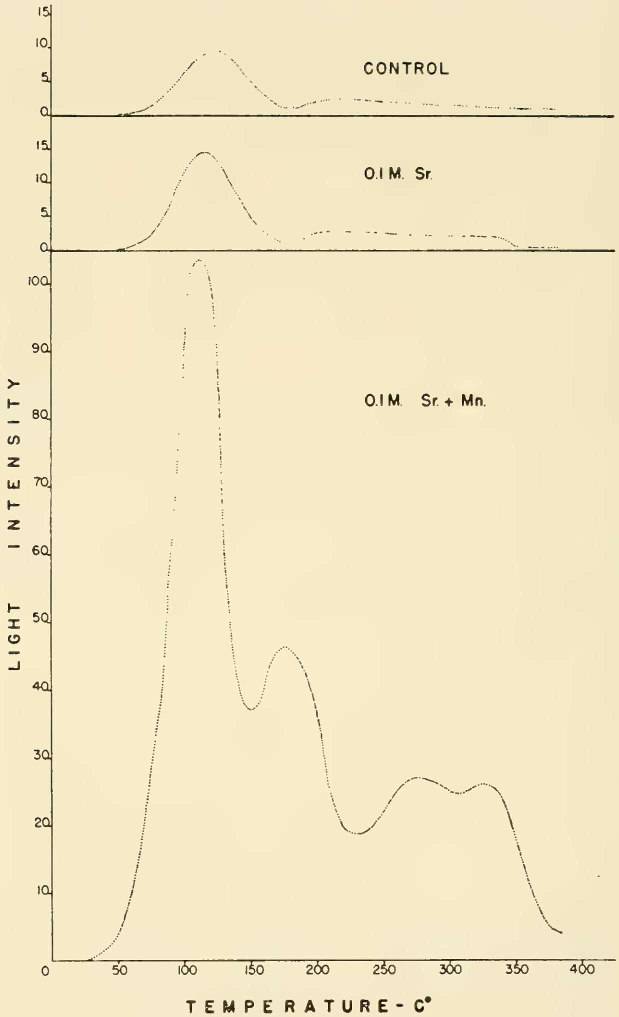

Figure 10-8. Effect of impurities on the thermoluminescence of laboratory precipitated calcium carbonate.

Pitrat (1956) studied the ratio of the intensity of different thermoluminescence peaks as a function of the magnesium content of limestone. His data are summarized in Figure 10-9.

Lewis (1956) has studied 18 different similar outcrop samples which show a graduation between calcite and 90 percent dolomite. They were powdered, exposed to gamma radiation, and preserved at dry-ice temperatures. Thermoluminescence glow curves were determined with 50-milligram of powder. Without irradiation, the samples give only one natural thermoluminescence peak at approximately 310C. After irradiation, both calcite and dolomite gave three well-defined peaks at 120C, 240C, and 310C. In calcite, the peak at 120C is much larger than it is in dolomite. The ratio of the peaks can be used to determine the percentage of calcite and dolomite in the rocks. $MgCO_3$ by itself has very little thermoluminescence.

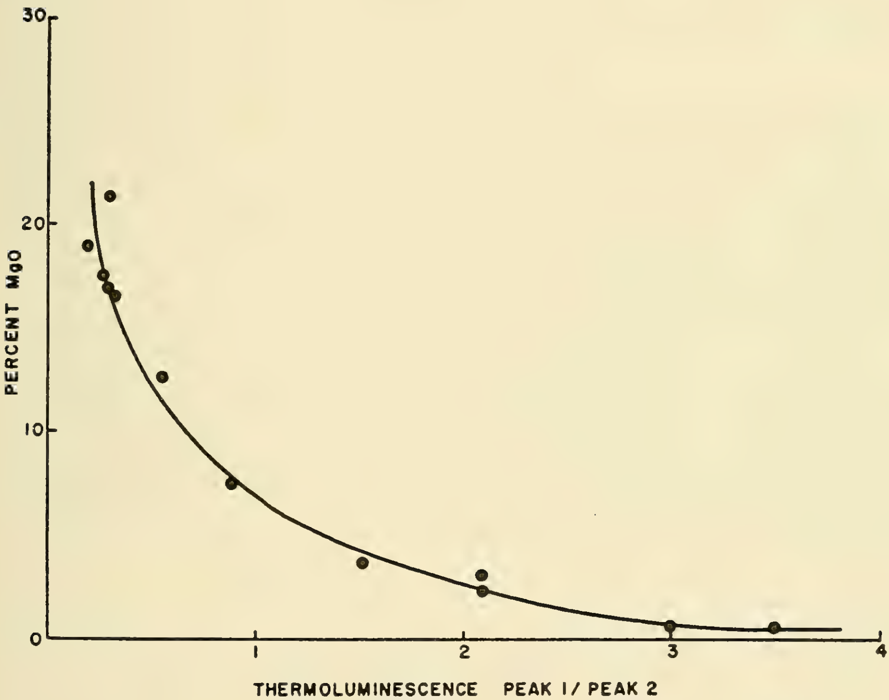

FIGURE 10-9. Relation of thermoluminescence to magnesium content of limestone.

OTHER MINERALS

Calcium fluoride in the form of fluorite minerals exhibits bright thermoluminescence after exposure to gamma rays or X-rays. Many fluorites have uranium as an impurity, or they have been exposed to gamma rays from adjacent radioactive minerals for geological ages so that they exhibit bright natural thermoluminescence and emit light on heating even without exposure to gamma radiation. Practically all granites, and particularly the feldspars, exhibit natural bluish thermoluminescence. Most granites contain more than 1 part per million of uranium and about 3 times as much thorium. This is sufficient to dislodge electrons, and they accumulate in traps and imperfections in the crystal lattice. Shales and lignite and many other rocks have radioactivity, but the crystal structure is not simple enough, hard enough, and transparent enough to show thermoluminescence.

RADIOACTIVITY OF ROCKS An extensive survey of the alpha radioactivity of many rocks and deposits has been made (Ockermann and Daniels, 1952) by using a specially designed scintillometer sensitive only to alpha particles. Eighty-two limestones gave an average radioactivity of 0.4 alpha particle (ranging from 0.05 to 1.7 alpha particle) emitted from a thick layer of powder per square centimeter per hour. Forty different granites gave an average of 3.2, ranging from 0.2 to 9.6 alpha counts per square centimeter per hour. Bentonites, residues from Wisconsin well waters and ash from plants gave still higher alpha particle counts. Such materials have the potential ability to produce thermoluminescence if the crystal lattices are suitable.

Certain old highly radioactive minerals containing rare earths have been subjected to such intense radiation damage that the crystal lattice has been so distorted that they show no diffraction patterns when a beam of X-rays is passed through them. Such minerals are called metamict crystals, and they may store up to 100 calories of energy per gram (Morehead and Daniels, 1952; Kurath, 1957), which is released as heat when the temperature is raised.

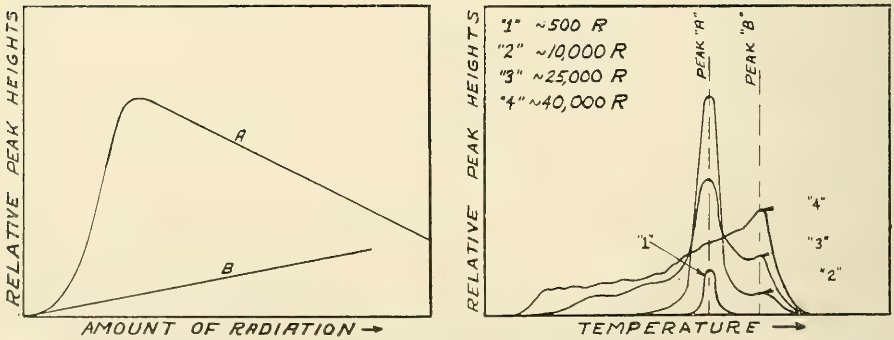

FIGURE 10-10. Effect of intense gamma irradiation on thermoluminescence glow curves of lithium fluoride.

Long intense exposure to radioactivity can produce new imperfections which provide new electron traps of different energies giving rise to new peaks in the thermoluminescence glow curves. Figure 10-10 illustrates the alterations that can be introduced into glow curves. Lithium fluoride gives a single peak when exposed to 500 roentgens of cobalt^{60}. An exposure of 10,000 roentgens increases the intensity of thermoluminescent light and starts a new peak corresponding to a new electron trap. Exposure to 25,000 roentgens creates more of the high-temperature traps, and 40,000 roentgens creates still more. When the radiation damage has become quite extensive, the thermoluminescence at the original peak decreases with further exposure.

STRATIGRAPHY Although the thermoluminescence glow curves vary greatly with impurities, conditions of crystallization and recrystallization, pressure, radioactivity, and age, they are reasonably characteristic of a particular sample of rock. If two rocks exhibit the same glow curves, they are likely to have had similar histories, including the deposition from water of about the same chemical composition. If the same sequence of thermoluminescence glow-curve patterns is found in two different locations, the geological history of the layers is probably the same.

Saunders (1953) was the first to apply thermoluminescence measurements to stratigraphy. His data are shown in Figures 10-11 and 10-12, where glow curves were obtained from a large quarry of Niagara limestone near Waukesha, Wisconsin. Figure 10-11 shows that in a single exposed thin bed extending for nearly half a mile, the glow curves taken at frequent lateral intervals are all the same. However, as shown in Figure 10-12, the glow curves vary greatly in the different layers as one takes samples of different layers over a vertical height of 25 feet. The conditions of chemical environment at the time of deposition are all the same on the lateral bed, but they differ considerably with the time of deposition, as indicated by the vertical sampling of the different layers. Long-distance correlation is much more uncertain, but Saunders found thermoluminescence evidence for the correlation of limestones from three different areas—the Pahasapa limestone of the Black Hills, South Dakota; the Madison limestone of the Wind River Mountains, Wyoming; and the Redwall limestone of the Grand Canyon, Arizona. All these limestones gave 3 definite peaks in the glow curves, but the peak heights varied to give 4 different types characterized by the relative heights of the peaks. The sequence of these 4 types in successive vertical layers was found to be the same in the 3 different areas· The probable correlation of the limestones in these areas had already been noted from geological evidence.

A summary of glow curves at different depths at a location in Iowa is shown in Figure 10-13. It is clear that the thermoluminescence patterns vary greatly

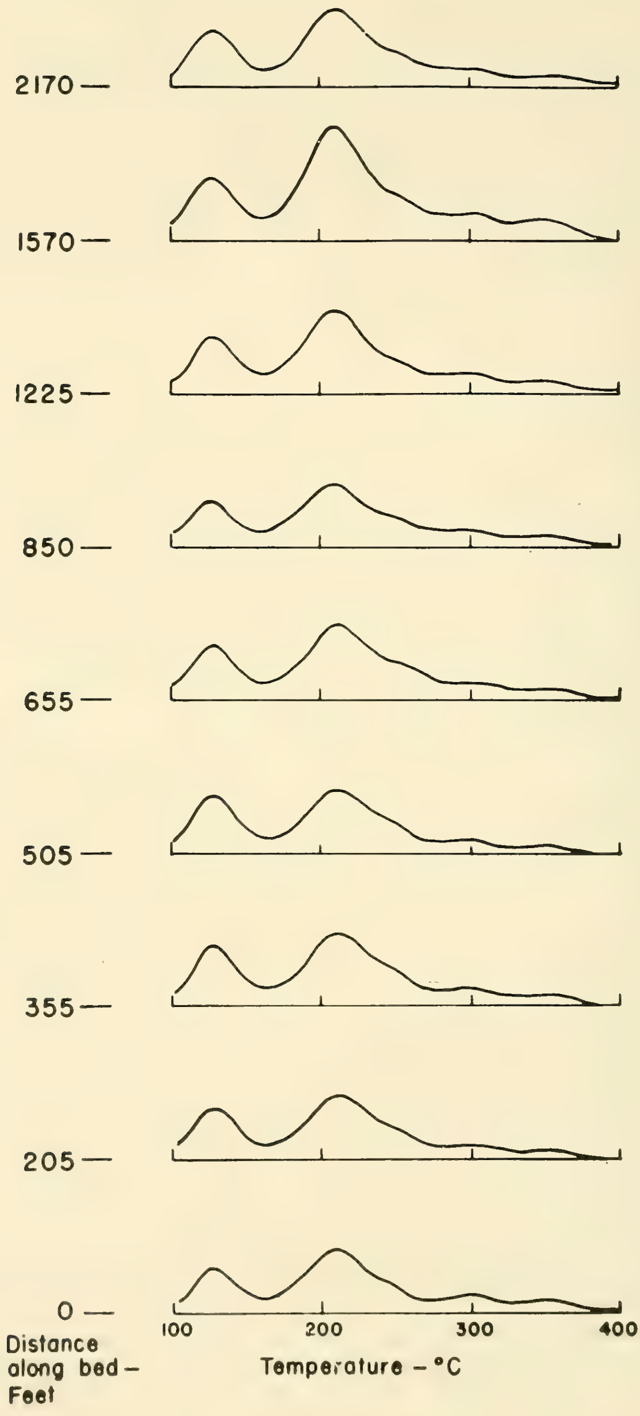

FIGURE 10-11. Glow curves of Niagrara limestone—lateral section of quarry.

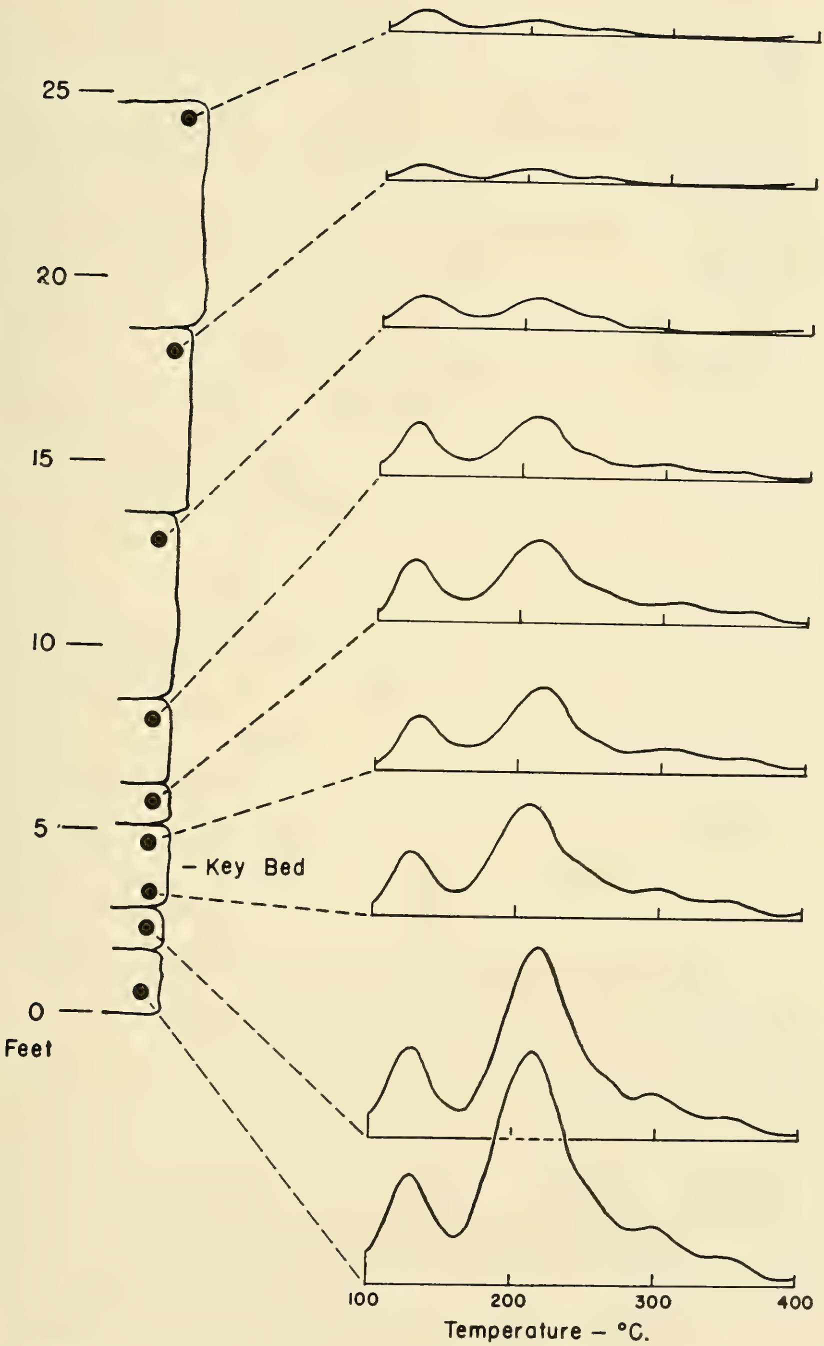

FIGURE 10-12. Glow curves of Niagrara limestone—vertical section of quarry.

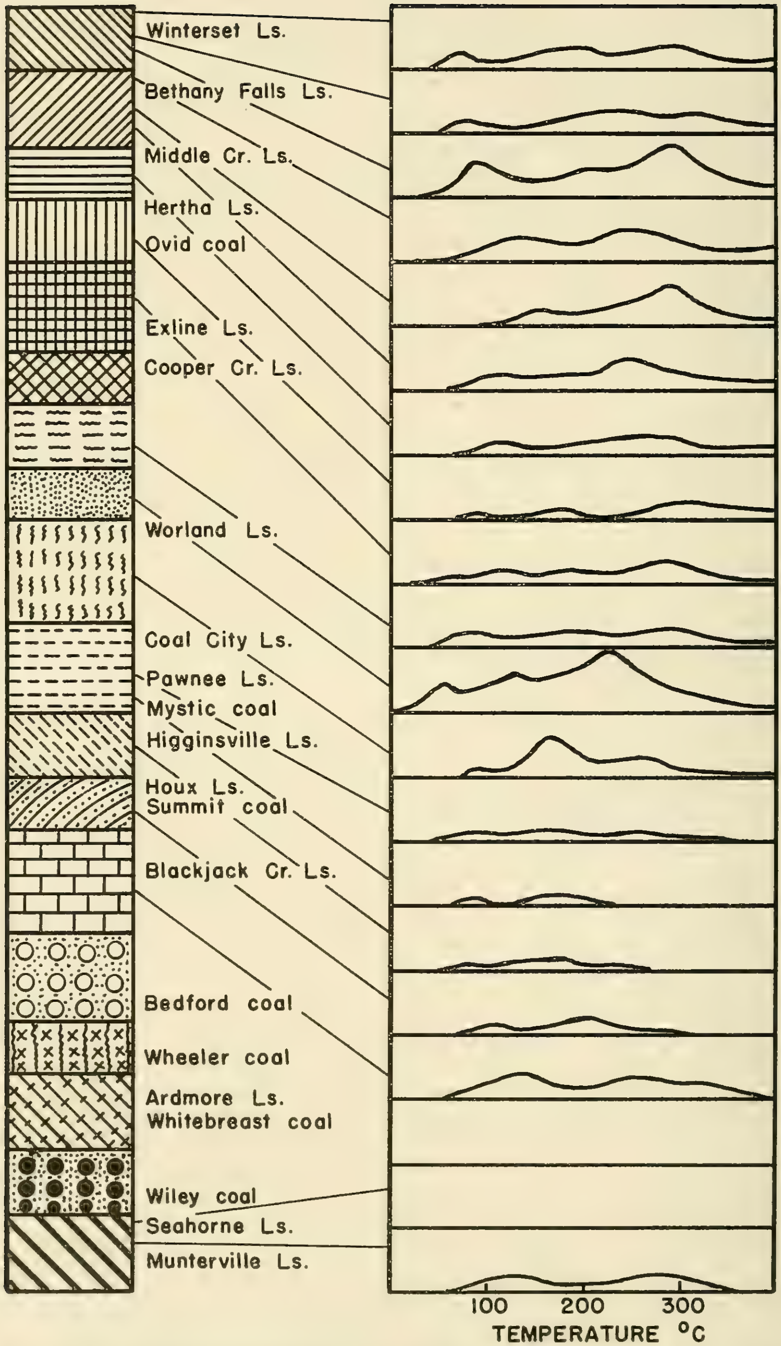

FIGURE 10-13. Schematic stratal sequence and glow curves from vertical section in Iowa.

with the strata and that the sequence of many such patterns provides a unique characterization in stratigraphy.

The thermoluminescence of Pennsylvanian limestones in Iowa, Missouri, and Kansas has been studied by Bergstrom (1953). He concluded that a glow-curve pattern may persist in a single thin bed and that successive layers in a vertical section can give cyclical variations. The chemical composition of the seas at the time of deposition appeared to be more important than the radioactivity as determined by the alpha counts. There was less variation in glow curves among samples taken deep in a basin than among samples taken near shore deposits where the chemical composition was subject to greater differences. Whenever there were lithological changes in the limestones, there were likely to be changes also in the glow-curve patterns. The quantity of acid-insoluble residues was measured, but is was difficult to establish firm correlations in thick widely separated beds.

Parks (1953) determined the thermoluminescence glow curves of surface samples and subsurface cuttings of the Chester series of Illinois, Indiana, and Kentucky. He used the heights of the high-temperature peaks and the ratio of the highest peak to the next lower peak as a means of correlation. There was considerable variation, but the sequence of glow-curve types in a vertical section was fairly consistent and could be used for approximate correlation.

Pitrat (1956) studied several limestones including the Madison limestones in Utah. He stressed the importance of taking unweathered samples which were as free as possible from secondary calcite and silica deposits. He kept the samples on dry ice after irradiation with gamma rays and in most samples observed three peaks. In a characteristic sample, the lowest peak at 75C had a relative height of 10, the 200C peak a height of 6.7, and the 300C peak a height of 3.2. In comparing the glow curves of the different samples, he tried relative peak heights, planimetered areas under the curves and ratios of the peak heights. The best results were obtained by comparing for the different samples the double ratio

$$\frac{\text{peak height 1}}{\text{peak height 2}} \div \frac{\text{peak height 2}}{\text{peak height 3}}$$

where numbers 1, 2, and 3 refer to the peaks at 75C, 200C, and 300C respectively. He also used a system of moving averages in which for a series of lateral samples he would take the average of the first, second, and third samples, then the average of the second, third, and fourth samples, and so on. He concluded that the variations are so great that detailed close sampling is not worthwhile, but he achieved some success in general correlations using these averages.

AGE DETERMINATION OF LIMESTONES Estimates of the age of limestones can be made from the intensity of thermoluminescence and the alpha-ray activity (Zeller, 1954; Zeller, and others, 1957). The glow curves of natural thermoluminescence, without laboratory exposure to gamma rays, are determined, and the areas under high temperature peaks from 250 to 375C are measured with a planimeter. The low-temperature peaks are not used because the long standing at earth temperature anneals out a good deal of the thermoluminescence. The number of alpha particles per hour per square centimeter emitted from a sample of the powdered material is measured with a special scintilometer (Ockermann and Daniels, 1954). The intensity of thermoluminescence light depends on the number of trapped electrons that are released, and the number of trapped electrons depends on the number of alpha particles and the length of time that they have been bombarding the crystal. If these three were the only variables, it would be fairly simple to determine the age from the alpha counts and the intensity of light. However, the thermoluminescence sensitivity of a rock to radioactivity varies greatly with the crystal structure and the impurities present. Accordingly, after the thermoluminescence glow curve has been determined, the sample is heated further to drain out all the accumulated, trapped electrons produced by natural radioactivity, and then it is exposed to gamma radiations from $cobalt^{60}$ ranging from 72,000 to 288,000 roentgens. The original intensity of the natural thermoluminescence at the high-temperature peaks is matched by a measured amount of gamma radiation, R_a, as read from the calibration curve. When these values of R_a are divided by the alpha counts, a number is obtained which is directly proportional to the geological age for the older limestones. The proportionality constant obtained from calibration curves permits an estimate of age since the last crystallization.

A complication was found in the corals and stalactites (Zeller, and others, 1957) and in the limestones of Recent and Tertiary ages. Their thermoluminescence was much too bright for the age and the alpha particle activity. Then it was found that fresh laboratory-precipitated crystals of calcium carbonate exhibit thermoluminescence even without exposure to X-rays or gamma rays (Zeller, and others, 1955), and this effect is increased greatly by pressure. Apparently pressure and crystallization can occasionally set up electrical charges which are sufficient to release electrons in a crystal lattice, just as radioactivity does, and some of these electrons become trapped for later emission of light when the crystal is heated. Zeller found that high pressures of several tons per square inch could be used to distinguish between the two kinds of thermoluminescence. High pressures increase the intensity of thermoluminescence of fresh crystals and geologically young limestones, whereas they decrease the thermoluminescence of geologically old limestones. They increase the crystallization-induced thermoluminescence, but decrease the radiation-induced thermoluminescence. In practice, glow curves are obtained for the compressed and uncompressed samples. If subjection to the high pressures causes the intensity of thermoluminescence to increase in the high-temperature peaks, the initial crystallization-induced thermoluminescence has not all been annealed out, and the age cannot be determined directly from the values of R_a and the alpha counts. If pressure does not increase the thermoluminescence, or if it decreases thermoluminescence, the measurements can be used for age determinations. It is clear that if later crystallizations have occurred, their ages will be obtained rather than the age of the original limestone. The age of early Tertiary limestones and older limestones as determined by thermoluminescence agreed with the age determined by fossils and standard geological evidence. The areas of the glow curves can be determined with an error of about 10 percent or less, and the counting of the alpha particles is probably the least accurate measurement. Again, if uranium or other elements producing alpha particles have been leached out, or if they have come in between grains at a later geological period, the age determinations will be subjected to serious error.

SUMMARY

The thermoluminescence of rocks and minerals provides a new type of measurement for crystals and minerals which may find applications in geology. The glow curves are greatly affected by impurities and geological history, and they are characteristic of a given sample. Most of the research has been concerned with limestones and the possibilities of using thermoluminescence as a tool in stratigraphy and in age determination. These researches on thermoluminescence for the past decade at the University of Wisconsin have been made possible by support from the Atomic Energy Commission.

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Chapter 11

MICROPALEONTOLOGICAL ANALYSIS

William S. Hoffmeister

INTRODUCTION

Micropaleontology, which is the science concerned with the study of ancient life, is useful for geologic and ecologic interpretations. Organisms, both animal and plant, that have left their remains or traces in the sedimentary strata of the geologic column are classified as fossils which are conveniently divided into two major groups: (1) macrofossils and (2) microfossils. As the names imply, macrofossils may be studied without a magnifying glass or microscope; microfossils are small forms that can be studied only at high magnifications.

Duties of Micropaleontologist

Although the duties of an economic micropaleontologist are largely concerned with the microfossils, a part of his time must be devoted to other techniques that aid in the solution of stratigraphic problems encountered in routine examination of samples. The few macrofossils found in well samples are commonly so broken by the drilling bit that identification is difficult. By far, the best tools for paleontological and paleoecological interpretations are the microfossils, although macrofossils are useful especially in Paleozoic rocks.

The purpose of this paper is to summarize: (1) the different types of microfossils likely to be encountered in well cuttings or cores; (2) their general descriptions; (3) their importance for correlation and paleoecological interpretations; and (4) their use in selecting and recommending favorable areas for petroleum exploration. The length of discussion of each group of microfossils will be relative to its considered future importance. Emphasis is placed on some of the microfossils, such as spores, pollen, hystrichospherids and microforaminifera that have been introduced only recently by oil companies into their paleontological laboratories.

One of the most important responsibilities confronting the oil company paleontologist is the rapid identification of the fossils encountered in routine examination of well samples. He must not only be able to recognize the fossils observed under the microscope, but know their geologic ranges and particular environment under which they were deposited. In a wildcat area this information must be relayed quickly to the well-site geologist so as to keep him informed of the age and, if possible, the depositional environment of the sediments being penetrated. Although the majority of proved field wells are correlated lithologically by the well-site geologist, information supplied to him by the micropaleontologist can aid him in correlating wells drilled on salt domes and other structurally complex areas. Unless he knows the age of the penetrated sediments, useless, expensive drilling might be continued in strata known to lack favorable reservoir rocks.

Until recently, paleontologists relied primarily on foraminifera for age determinations and zonal correlation. In many instances foraminifera are scarce and poorly preserved, and they are not indicative of age nor of value as zone markers. Where the strata are barren of foraminifera, the stratigrapher must rely primarily on lithology and electric logs for establishing correlations.

Plant spores, pollen, hystrichospherids, or other types of microfossils are found in approximately 90 percent of all sediments. Because of this wide dispersal, the economic paleontologist has an excellent opportunity (1) to make rapid age determinations, (2) to correlate the strata, and (3) to evaluate formations for oil possibilities.

Wilson (1956) pointed out that a paleontologic study that utilizes all the organisms present to determine paleoecological conditions should be of proportionally greater value to stratigraphy than one devoted to a single group of fossil animals or plants. The economic paleontologist of today should be well acquainted with various types of microfossils so that more critical evaluation of composite assemblages can be made. Many oil-company paleontologists have disregarded all microfossils except the foraminifera, and thus have by-passed much useful information.

Zoning

It is desirable in many instances to zone a formation so that more accurate correlations can be made. Microfossil zones are established by three methods:

(1) appearance; by noting the first occurrence of new forms or different assemblages; (2) population counts; by counting a given number of individuals (200 is generally sufficient) of a certain group of microorganisms and plotting the percentages of each genus or species in histogram form. It is sometimes possible to detect significant changes within that group which may be used as correlation points; and (3) paleoecological analysis; the ratio of plant microfossils to brackish or marine animal microfossils may be used as an aid in interpreting depositional environments. In some studies it may be advantageous to revert to all three methods.

Favorable Areas for Oil Exploration

Oil is found generally rimming ancient depositional basins; seldom is it found in the center of these basins. It is, therefore, important for the petroleum geologist to interpret the paleoecological or ancient environmental conditions in the area under exploration. Microfossils furnish excellent means for recognizing these environments. In general, the presence of only spores and pollen, or *Pediastrum* or Charophyta or fresh-water ostracodes in a sample would indicate that the sediment was probably a continental deposit or was laid down close to an ancient shoreline. On the other hand, a sample containing mostly hystrichospherids or scolecodonts would suggest a brackish to marine environment. Material containing foraminifera, discoasterids, radiolarians, chitinozoans, silicoflagellates, echinoid or coral fragments would indicate an offshore or marine environment. A study of bottom samples from the Gulf of Mexico and from the Atlantic Ocean has shown a decrease in plant microfossils away from the shore, an increase of the hystrichospherids in the brackish to marine environments, and a steady increase in the microforaminifera seaward. The results of this study can be applied to ancient basins.

If a series of composite samples from a particular time-rock unit can be taken from several different boreholes, it is possible to approximate the position of ancient shorelines. To do this, the specimens from each particular group of microfossils—spores and pollen, hystrichospherids, microforaminifera, etc.—are counted in each sample. Isobotanical lines are drawn on the abundance of spores and pollen per gram of sediment and isozoological lines are drawn on the abundance of hystrichospherids, microforaminifera, or other groups of animal microfossils per gram of sediment.

The isobotanical lines parallel the approximate position of the ancient shore and the general trend of oil fields. In addition, those isobotanical lines representing the greater abundance of spores and/or pollen are near the loci of oil-bearing areas, whereas, the isozoological lines, indicating the greater abundance of hystrichospherids or marine animals, are farthest removed from the oil-bearing areas. To determine the direction of the shoreline, it is necessary to study composite samples from at least three boreholes triangularly arranged. By counting the plant spores in the Morrow and Atoka formations from numerous wells in the Seminole area of Oklahoma, it was found that the isobotanical lines showing the greatest abundance of spores were parallel and nearest to oil fields. In areas which consistently had dry holes, the sediments contained very few spores.

In a broad sense, an abundance of plant spores and pollen could indicate a favorable area for oil exploration where the reservoir rock is sandstone; an abundance of hystrichospherids might indicate a favorable area for petroleum possibilities where the reservoir is a reefal limestone; and the abundance of microforaminifera could indicate an unfavorable area for oil accumulation because reservoir rocks might be lacking.

Preparation Techniques

The remains of microfossils are either calcareous, siliceous, chitinous, proteinaceous, cellulose, phosphatic, or carbonaceous. To obtain the different types of microfossils from a particular sample, it is necessary to divide the material so that separate preparation methods can be used for each portion of the sample, depending on the chemical composition of the microfossils, their size, and the character of the sediment. Because of differences in composition of microfossils and their entombing sediments, preparation procedures will vary not only with a particular sample but also with different types of lithology. Space does not permit an account of the various preparation techniques. The reader should, therefore, refer to the published details of these methods, which are generally included in papers dealing with particular groups of microfossils. However, some general preparation techniques are briefly described below.

For Acid-Soluble Microfossils

The sample, if not indurated, is broken into ±1/4-inch fragments and soaked in water (boiled if necessary) for several hours. It then is washed through a nest of sieves (80, 100, 150 mesh) to remove the fine clastics. In some instances, it is feasible to concentrate the microfossil assemblage by heavy liquids such as bromoform or carbon tetrachloride. If the sample is well indurated, it may be necessary to prepare thin sections for studying the microfossil content.

For Acid-Insoluble Microfossils

The shale sample is broken into fragments ±1/4-inch. It is then placed in a copper beaker, covered with 52 percent hydrofluoric acid, and allowed to remain under a hood for 16 hours; or the sample can be boiled in the acid for 5 minutes if rapid examination is desired. The residue is then diluted with distilled water and is centrifuged repeatedly until all acid is removed. A few drops of a 1 percent solution of Safranine Y stain is then added. The sample is then ready for examination. Permanent slides are prepared by mounting the residue in glycerine jelly.

In macerating coals for plant microfossils, a different technique is followed. The sample, after being broken into ±1/2-inch fragments, is placed in a glass beaker. Schultze's solution (saturated solution of 1 part potassium chlorate to 2 parts concentrated nitric acid) is added. After 12 hours under the hood, the solution is diluted with distilled water and centrifuged; the liquid part is discarded. The residue is then covered with ammonium hydroxide and allowed to stand for approximately 2 minutes, after which time it is diluted with distilled water and centrifuged. Washing is repeated several times.

SUMMARY OF IMPORTANT MICROFOSSILS

L. R. Wilson (1956) lists important microfossils and separates them into three major divisions: (1) plant microfossils, (2) animal microfossils, and (3) microfossils of uncertain affinity. For each group, Wilson includes type, description, geologic range, habitat, size, and method of recovery. Wilson's sequence is followed in the ensuing discussion. (See fig. 11-1.)

Plant Microfossils

Bacteria

Probably the oldest known microfossils are bacteria. They have a geologic range from the Algonkian to Recent. Although found in various rock types, including oil shale, their value to the subsurface geologist is limited because of their extremely small size and their uncertain ecological significance. Bacteria are microscopic globose to rod-shaped, unicellular organisms found as isolated cells or in chain-like arrangements.

Coccolithaceae (Pl. 11-I, fig. 1)

Little is known about the coccoliths (Coccolithaceae, Coccolithophoridae). These minute (2-15 microns) marine, planktonic forms have been assigned to the algae by some workers and by others to the Protozoa. The living form includes a spherical cell whose walls are composed of small calcareous plates referred to as coccoliths. Classification of the coccoliths is based upon the morphologic character of the plates, the most common being the perforate or imperforate disks. Although coccoliths have been reported in Upper Cambrian sediments, it was not until late Mesozoic that they became abundant. When better understood, these comparatively unknown organisms may show promise of becoming important in biostratigraphic studies.

SUMMARY OF IMPORTANT MICROFOSSILS

Plant Microfossils

TYPE	DESCRIPTION	GEOLOGIC RANGE	HABITAT	SIZE	RECOVERY
Bacteria	Cellulose Single cells, chains	Pre-Cambrian — Recent	All	ca. 1μ	Thin section
Coccolithaceae	Calcareous Imperforate and perforate plates	Cretaceous — Recent	Marine	2 — 3μ	Thin section
Silicoflagellata	Siliceous Rings, nets, etc.	Cretaceous — Recent	Marine	25 — 80μ	Dispersion KOH, HCl, HNO_3, H_2SO_4 Thin section
Dinoflagellata	Cellulose, proteinaceous Cell wall with furrows	Jurassic — Recent	Fresh, brackish, marine	25 —125μ	Dispersion KOH, HCl, HNO_3, H_2SO_4 Thin section
Desmidaceae	Cellulose Single cell constricted in middle	Tertiary — Recent	Fresh water	0.1 — 0.5 mm.	KOH, HCl, HF
Other Chlorophyceae	Cellulose Single or colonial spheres, masses, plates, filaments	Tertiary — Recent	Fresh water	0.1 — 2 mm.	KOH, HCl, HF
Diatomaceae	Siliceous Single cell, discoidal, rhombic, elliptic, triangular	Cretaceous — Recent	Fresh, brackish, marine	5 — 60μ	HCl, HNO_3, H_2SO_4
Charophyta	Calcareous Spheres, ovoids, spiral aspect	Devonian — Recent	Fresh, brackish	1 — 3 mm.	Dispersion Thin section
Spores	Cellulose Single or groups, spheres, ovoids, etc.	Silurian — Recent	Terrigenous, fresh, brackish, marine	10 — 900μ	Dispersion KOH, HCl, HF, Schultze Solution Thin section
Pollen: Gymnospermae	Cellulose Single cells, several cells, masses	Devonian — Recent	Terrigenous, fresh, brackish, marine	10 — 130μ	Dispersion KOH, HCl, HF, Schultze Solution Thin section
Pollen: Angiospermae		Jurassic — Recent			
Trichomes	Cellulose Single to multicellular, spines, plates, etc.	Silurian — Recent	Terrigenous, fresh	20μ +	Dispersion KOH, HCl, HF Thin section
Leaf cuticles	Cellulose Cellular or noncellular	Silurian — Recent	Terrigenous, fresh, brackish, marine	10μ +	Dispersion KOH, HCl, HF, Schultze Solution Thin section
Isolated tissues or cells	Cellulose Single to multicellular fragments	Silurian — Recent	Terrigenous, fresh, brackish, marine	10μ +	Dispersion KOH, HCl, HF, Schultze Solution

ANIMAL MICROFOSSILS

TYPE	DESCRIPTION	GEOLOGIC RANGE	HABITAT	SIZE	RECOVERY
Foraminifera	Calcareous, arenaceous, chitinous Simple to complex chambers, and chamber linings	Cambrian — Recent	Marine	30μ +	Dispersion HF Thin section
Radiolaria	Siliceous Single cells, spherical or bell-shaped	Pre-Cambrian — Recent	Marine	50 — 500μ	Dispersion HCl, HNO_3, H_2SO_4 Thin section
Calpionellidae	Calcareous Unilocular, cup-shaped	Up. Jurassic — L. Cretaceous	Marine	25 × 50μ	Thin section
Porifera	Calcareous, siliceous Simple to complex spicules and fibers	Pre-Cambrian — Recent	Fresh, brackish, marine	50μ — 3 mm.	Dispersion HCl, HNO_3, H_2SO_4 Thin section
Alcyonarian spicules	Calcareous, horny? Acicular, granular, glossy	Up. Cretaceous — Tertiary	Marine	1 — 3 mm.	Dispersion Thin section
Echinodermata	Calcareous Plates, discs, columnals, spines, etc.	Ordovician — Recent	Marine	0.5 mm. +	Dispersion Thin section
Ostracoda	Calcareous, chitinous Carapaces, appendages	Ordovician — Recent	Fresh, brackish, marine	0.5 — 5 mm.	Dispersion Thin section
Other Arthropoda	Chitinous Skeletal fragments	Cambrian — Recent	Fresh, brackish, marine	50μ +	Dispersion HCl, HF Thin section
Scolecodonts	Chitinous Jaws, cusps	Cambrian — Recent	Brackish, marine	50μ — 5 mm.	Dispersion HCl Thin section
Conodonts	Phosphatic Plates, cuspate jaws	Cambrian — Triassic	Marine	100μ — 3 mm.	Dispersion HAc Thin section

MICROFOSSILS OF UNCERTAIN AFFINITY

TYPE	DESCRIPTION	GEOLOGIC RANGE	HABITAT	SIZE	RECOVERY
Discoasteridae	Calcareous Discs, asters	Up. Cretaceous — Tertiary	Marine	20 — 35μ	Dispersion HF
Hystrichosphaerida	Proteinaceous Spheres, ovoids, spiny, smooth	Pre-Cambrian — Recent	Brackish, marine	10 — 400μ	Thin section HCl, HF
Chitinozoa	Proteinaceous? Tubes, flasks, urn-shaped	Cambrian — Mississippian	Marine	50μ — 1 mm.	Thin section HCl, HF
Nannoconus	Calcareous Cone-like, central canal, wedge-shaped elements	Jurassic — Cretaceous	Marine	100 — 180μ	Thin section
Oligostegina	Calcareous Spheres	Cretaceous	Marine	50μ +	Thin section
Fragmenta	Calcareous, carbonaceous Spheres, masses, spines, etc.	Pre-Cambrian — Recent	Fresh, brackish, marine	10μ +	Thin section HCl, HF

(From Wilson, *Micropaleontology* V. 2, No. 1.)

FIGURE 11-1. Summary of important microfossils. (Wilson)

Silicoflagellata (Pl. 11-I, figs. 2-4)

Like the Coccolithaceae to which they are apparently related, the silicoflagellates are small (25-80 microns) marine planktonic forms. They are widely distributed in the present oceans. As in the case of the Coccolithaceae, some workers refer them to the algae, whereas others place them within the Protozoa. The silicoflagellates have siliceous skeletons composed of a simple combination of spines, arcs, nets, and thin rings. They occur in Cretaceous and Tertiary rocks and are especially abundant in diatomaceous sediments. Silicoflagellates are being used currently for correlation purposes and as indicators of marine conditions.

Dinoflagellata (Pl. 11-I, fig. 5)

Dinoflagellates are small (25-125 microns) planktonic organisms which are considered by some workers to be algae and by others to be Protozoa. Their wall cells or coats, which are cellulose, may be smooth and consist of two valves, or they may be spiny and divided by furrows into angular plates. Their geologic range is Jurassic to Recent.

Representatives of this group are found in residues prepared for other acid-insoluble organisms such as hystrichospherids, to which they may be related. The dinoflagellates are rapidly becoming useful to the economic paleontologist. Although this group is generally found in a marine environment, representatives are known also from fresh and brackish waters.

Desmidaceae (Pl. 11-I, fig. 19)

Desmids are algae (Chlorophyceae) whose acid-resisting cell walls contain vertical pores through the innermost and median wall layers. Although most of the desmids are unicellular, some have their cells united in filaments of various lengths. They are found associated with free-floating algae in fresh water. Representatives of this group are so different in shape and ornamentation that even a general description here would be difficult. Fossil forms have been noted in Tertiary and Recent deposits. They are useful to the economic paleontologist because they are limited to fresh water.

Other Chlorophyceae (Pl. 11-I, fig. 15)

Other Chlorophyceae important to the paleontologist include the genus *Pediastrum* of the family Hydrodictyaceae. This genus is characterized by a coenobium (a colony of cells) usually composed of 4 to 64 cells. It is found in fresh water sediments from Tertiary to Recent.

Diatomaceae (Pl. 11-I, figs. 6-11)

Diatoms differ from other algal forms principally because their cell walls are siliceous and consist of two closely fitting or overlapping halves. As in other

PLATE 11-I

1—Coccolith, schematic drawing of a coccosphere, diameter 10 microns, Jurassic to Recent.

2—*Dictyocha* sp., diameter 76 microns, Tertiary, California.

3—*Naviculopsis* sp., size 19 x 168 microns, Tertiary, California.

4—*Vallacerta* sp., diameter 58 microns, Cretaceous, California.

5—*Gonyaulax jurassica* Deflandre (?), length 100 microns, Curtis formation, Upper Jurassic, Utah.

6—*Actinoptychus* sp., diameter 94 microns, Tertiary, California.

7—*Triceratium* sp., diameter 85 microns, Tertiary, California.

8—*Suriella* sp., size 80 x 180 microns, Tertiary, California.

9—*Coscinodiscus* sp., diameter 82 microns, Tertiary, California.

10—*Biddulphia* sp., size 60 x 228 microns, Tertiary, California.

11—*Triceratium* sp., length 90 microns, Tertiary, California.

12—*Aclistochara clivulata* Peck and Reker, lateral view, length 1 mm., Middle Eocene, Florida. (Peck and Reker, Jour. Paleontology, v. 22)

13—*Aclistochara clivulata* Peck and Reker, basal view, diameter 0.87 mm., Middle Eocene, Florida. (Peck and Reker, Jour. Paleontology, v. 22)

14—*Aclistochara coronata* Peck and Reker, lateral view, length 0.73 mm., Lower Eocene, Wyoming. (Peck and Reker, Jour. Paleontology, v. 22)

15—*Pediastrum kajaites* Wilson and Hoffmeister, diameter 132 microns, Lower Formation (Paleogene), Sumatra.

16—Cuticle type A Wilson and Hoffmeister, cell size, length 39-58 microns, width 5-18 microns, Middle Pennsylvanian, Oklahoma. (Okla. Geol. Survey, Circular 32)

17—Sporange cuticle, cell size, 80 x 180 microns, Tertiary, Wyoming.

18—Abitineae type border pits, size 20 x 58 microns, diameter of pits 18 microns, Mesozoic (?), Florida.

19—*Staurastrum paradoxum* Meyen, diameter 1 mm. (fresh-water algae of the United States, Smith 1950).

20—*Chamaedaphne calyculata,* size 31 x 40 microns, Pleistocene, Massachusetts.

21—Unicellular trichome, size 12 x 72 microns, Pleistocene, Massachusetts.

22—*Sheperdia canadensis,* fragment, diameter 430 microns, Pleistocene, Massachusetts.

23—Sponge spicule, size 96 x 220 microns, Tertiary, New Zealand.

24—Sponge spicule, size 24 x 140 microns, Cretaceous, California.

25—Sponge spicule, size 24 x 158 microns, Tertiary, New Zealand.

26—Sponge spicule, size 13 x 240 microns, Tertiary, New Zealand.

27—Alcyonarian spicule after Wright, size 1-3 mm., Recent. (Principles of micropaleontology, Glaessner 1944)

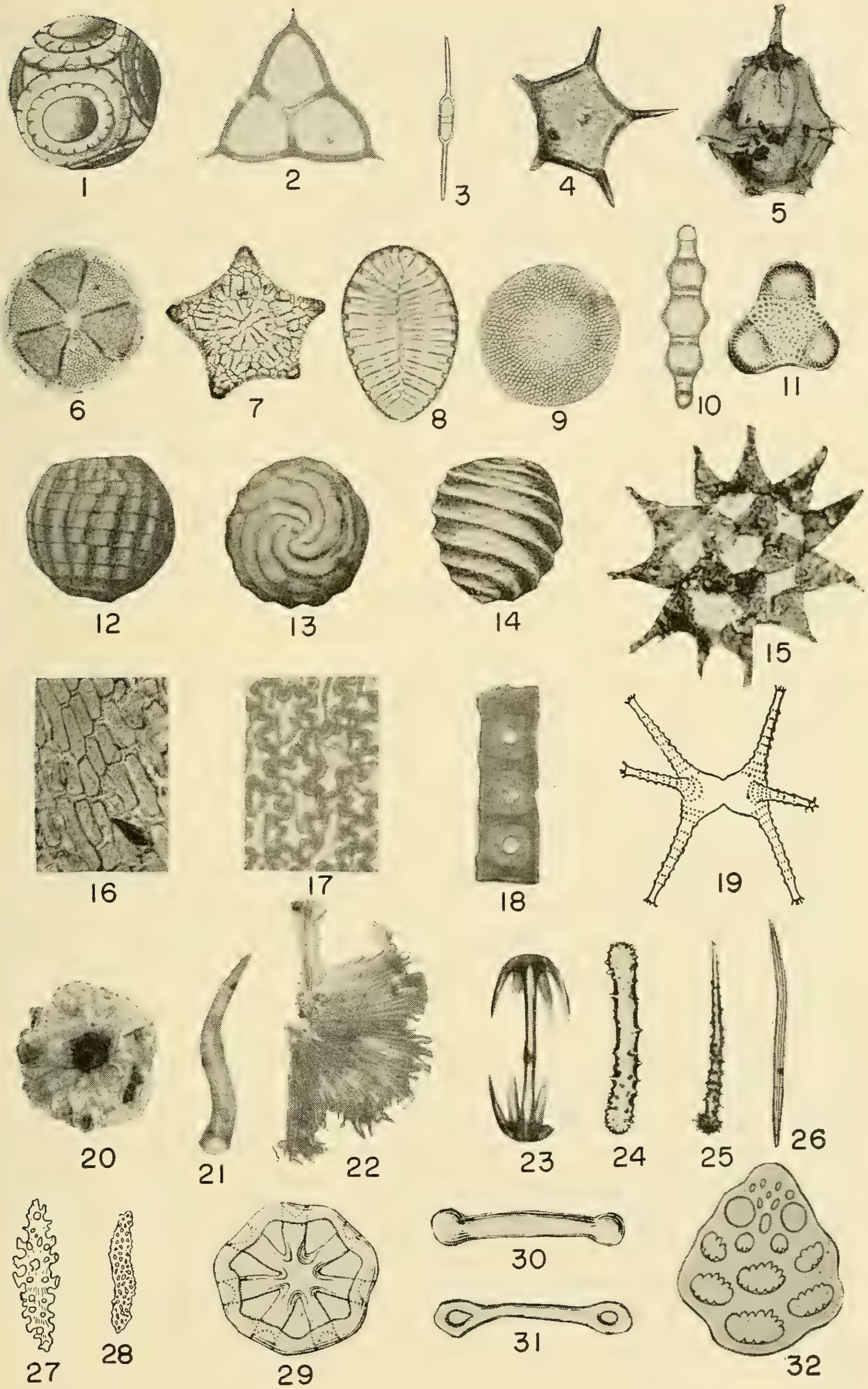
28—Alcyonarian spicule after Pocta, size 1-3 mm., Upper Cretaceous, Bohemia. (Principles of micropaleontology, Glaessner 1944)

29—*Theelia undulata* (Schumberger), diameter 0.20 mm., Eocene, France. (Frizzell and Exline, Missouri School of Mines Tech. Ser., No. 89, 1955)

30—*Rhabdotites mortenseni* Deflandre-Rigaud, length 1.02 mm., Jurassic, Germany. (Frizzell and Exline, *op. cit.*)

31—*Binoculitites terquemi* Deflandre-Rigaud, length 0.56 mm., Jurassic, Germany. (Frizzell and Exline, *op. cit.*)

32—*Synaptites eocoenus* (Schlumberger), length 0.18 mm., Eocene, France. (Frizzell and Exline, *op. cit.*)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algae, the diatoms have numerous shapes and structures (discoid, elliptic, rhombic, triangular, etc.). They are found in fresh, brackish, and marine sediments and have a geologic range from the Cretaceous to Recent. Like pelagic foraminifera, diatoms are used sometimes for long-distance correlation.

Charophyta (Pl. 11-I, figs. 12-14)

The Charophyta or stoneworts are algae believed to be distantly related to the Chlorophyceae. They are composed of erect stems consisting of nodes and internodes. The fossil remains of the Charophyta are formed by an accumulation of calcium carbonate about the plant; usually only the female reproductive body, the oogonium, is found fossilized. The oogonia have characteristic spiral ornamentation which make them easily recognizable. Stoneworts with sinistral spiraling are known from the Devonian to Recent and those with dextral spiraling from the Lower Devonian to Lower Mississippian.

Recent Charophyta occur in fresh- and brackish-water environments. However, some workers believe that the earlier forms may have had near-shore and marine habitats. More work is needed on these interesting fossils before they can be used in close correlation work. At the present they are valuable only in determining broad geologic time subdivisions.

Plant Spores and Pollen

Plant spores and pollen have become very useful and adaptable in stratigraphic paleontology during the last decade. The present status of these plant microfossils is comparable to that of foraminifera thirty years ago. More and more oil companies, recognizing the stratigraphic importance of these microfossils, are adding personnel to their paleontological staffs for the purpose of investigating these fossils.

Plant spores were observed as early as 1833 by Witham, who described them from bituminous coals in England. Since 1930, workers have used them for the recognition and correlation of coal seams both in this country and abroad. The Illinois State Geological Survey and others have done extensive work using fossil spores for correlating Paleozoic coals.

Unlike the foraminifera, which are confined almost entirely to marine sediments, spores and pollen occur in both marine and non-marine strata. Spores and pollen are widely distributed in a variety of sediments by wind, water, gravity, and insects. Foraminifera have different representatives in each type of the different marine environments, such as near shore, offshore, shallow water, and deep water. Therefore correlation across facies boundaries is often difficult. In contrast, the same species of spores and pollen are encountered in rocks laid down in all types of environment, thereby permitting correlation across different depositional facies.

Generally, spores (Pl. 11-II, figs. 1-14) are the reproductive bodies of the nonflowering plants, whereas pollen grains (Pl. 11-II, figs. 15-29) are the male reproductive bodies of the flowering plants. Morphologically spores are characterized by sutures, and pollen by furrows and pores. These sutures, furrows, and pores are associated with the germination process and serve as openings through which the plant reproductive cells escape.

Plant spores, having been studied more extensively than pollen, are better understood; therefore, their classification is better established.

The oldest known spores of vascular plants are from the Silurian. Lang and Cookson (1935) reported plants possessing cuticles, stomata, and lignified vascular tissue from the Silurian rocks of Australia. Until the discovery of spores in the Silurian of New York State, the oldest known spores in this country were from the Devonian. Although spores have been reported from pre-Silurian rocks, most of these reports come from areas where the structural and stratigraphic sequences are poorly controlled. The writer knows of no undoubted vascular plant remains from pre-Silurian rocks.

The earliest pollen grains are found in Carboniferous rocks, although it is not until the Cretaceous that angiosperm pollen are encountered in abundance and variety. The Permian and Triassic pollen are from the gymnosperms (Pl. 11-II, figs. 15-19), which are similar to the modern pines, spruces, cycads, and hemlocks. The earliest known angiosperm pollen (Pl. 11-II, figs. 20-29) occur in the Jurassic.

Trichomes (Pl. 11-I, figs. 20-22)

Trichomes, or epidermal hairs, which are usually hair-like branching or plate-like outgrowths of the epidermis of plant leaves and stems, are found in sediments from Silurian to Recent. They should be useful to the paleontologist when better understood. Because they are cellulose, the trichomes are found in the residues prepared for other acid-insoluble microfossils.

Leaf Cuticles (Pl. 11-I, figs. 16, 17)

The outer films and epidermal cells with stomatal structures are the leaf cuticles which currently are being used to a minor degree in microfossil work. Like the trichomes, their geological range is Silurian to Recent. Histograms of cuticles from the same coal over a wide areal extent show remarkable similarity (Wilson and Hoffmeister, 1956). These forms are insufficiently understood to be useful in narrow stratigraphic determinations, but appear to have some ecological significance by indicating the type of vegetation that was localized within a particular vicinity.

PLATE 11-II

1—*Divisisporites* (?) sp., size 50 x 56 microns, Williamson Shale, Silurian, New York.

2—Undescribed spore, diameter 130 microns, Duvernay formation, Devonian, Alberta, Canada.

3—*Reinschospora* sp., size 39 x 41 microns, Springer Shale, Lower Pennsylvanian, Oklahoma.

4—*Florinites antiques* Schopf, size 57 x 75 microns, Croweburg Coal, Middle Pennsylvanian, Oklahoma. (Okla. Geol. Survey, Cir. 32)

5—*Densosporites tenuis* Hoffmeister, Staplin and Malloy, size 57 x 64 microns, Hardinsburg formation, Upper Mississippian, Illinois and Kentucky. (Mississippian Plant Spores from the Hardinsburg formation of Illinois and Kentucky; Jour. Paleontology v. 29)

6—*Triquitrites additus* Wilson and Hoffmeister, size 40 x 43 microns, Croweburg Coal, Middle Pennsylvanian, Oklahoma. (Okla. Geol. Survey, Cir. 32)

7—*Laevigatosporites ovalis* Kosanke, size 32 x 46 microns, Croweburg Coal, Middle Pennsylvanian, Oklahoma. (Okla. Geol. Survey, Cir. 32)

8—*Tripartites vetustus* Schemel, diameter 43 microns, Hardinsburg formation, Middle Pennsylvanian, Kentucky. (Jour. Paleontology, v. 29)

9—*Alatisporites* sp., overall diameter 83 microns, Tebo Coal, Middle Pennsylvanian, Kansas.

10—*Schopfites colchesterensis* Kosanke, diameter 78 microns, Croweburg Coal, Middle Pennsylvanian, Oklahoma. (Okla. Geol. Survey, Cir. 32)

11—*Raistrickia aculeolata* Wilson and Hoffmeister, diameter 50 microns, Croweburg Coal, Oklahoma. (Okla. Geol. Survey, Cir. 32)

12—*Granulatisporites adnatus* Kosanke (?), diameter 38 microns, Croweburg Coal, Middle Pennsylvanian, Oklahoma. (Okla. Geol. Survey, Cir. 32)

13—*Aneimia phyllitides,* diameter 84 microns, Recent, Florida.

14—*Dryopteris* sp., size 24 x 41 microns, Recent, Massachusetts.

15—*Cycas* sp., size 19 x 38 microns, Recent, Florida.

16—*Tsuga canadensis,* diameter 80 microns, Pleistocene, Massachusetts.

17—*Taxodium* sp., length 38 microns, Pleistocene, Louisiana.

18—*Picea glauca,* length 88 microns, Pleistocene, Massachusetts.

19—*Pinus banksiana,* length 56 microns, Pleistocene, Massachusetts.

20—*Carpinus* sp., diameter 32 microns, Pleistocene, Massachusetts.

21—*Tilia* sp., diameter 35 microns, Calvert formation, Miocene, Virginia.

22—*Nymphacea* sp., size 31 x 60 microns, Pleistocene, Massachusetts.

23—*Betula* sp. (usually 3 pores), diameter 26 microns, Pleistocene, Wisconsin.

24—*Andromeda glaucophylla,* diameter 41 microns, Recent, Wisconsin.

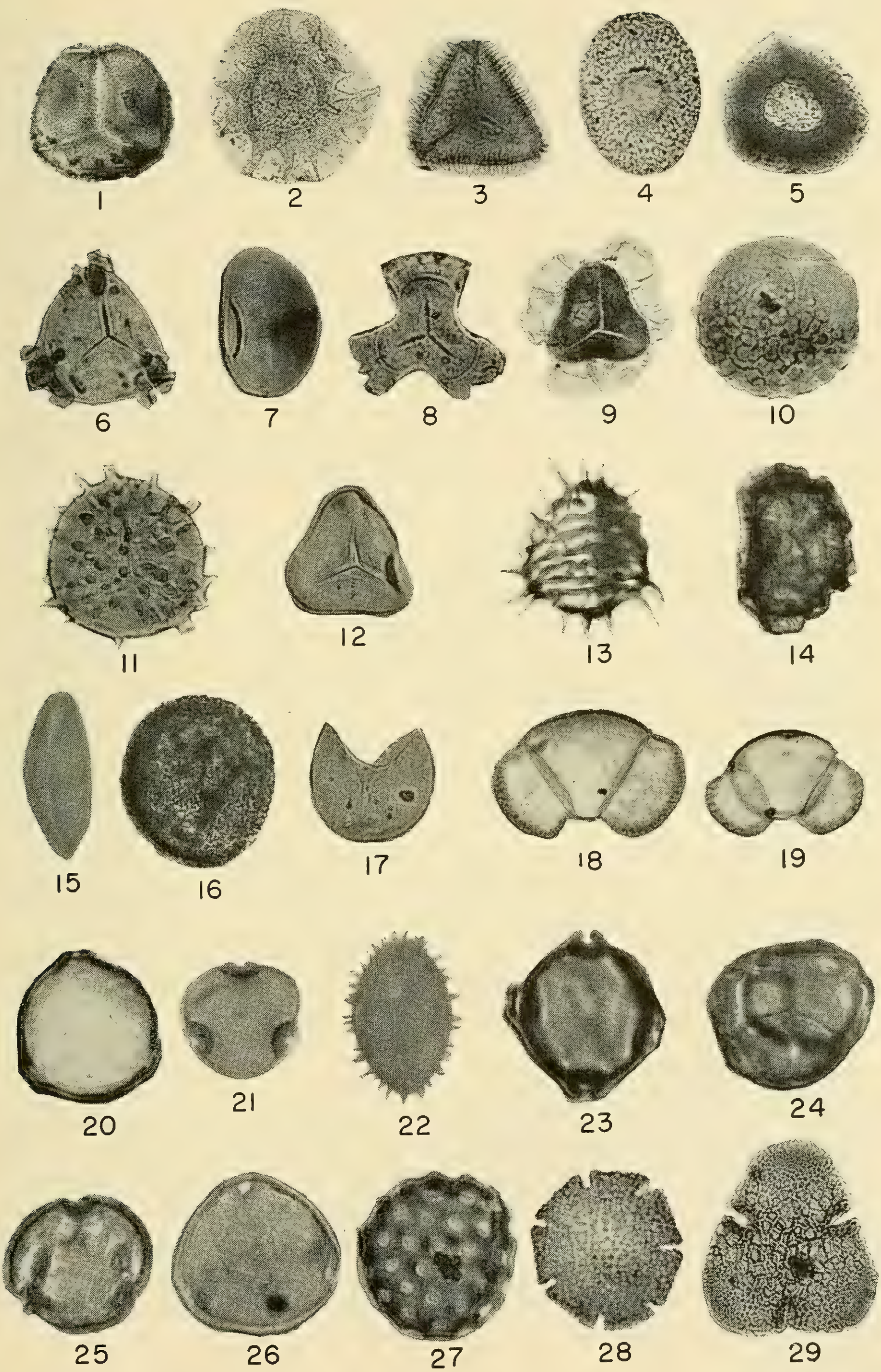
25—*Quercus* sp., diameter 35 microns, Pleistocene, Massachusetts.

26—*Carya* sp., diameter 40 microns, Pleistocene, Wisconsin.

27—*Chenopodium* sp., diameter 27 microns, Calvert formation, Miocene, Virginia.

28—*Nothofagus* sp., diameter 25 microns, Miocene, Victoria, Australia.

29—*Tricolporitae* sp. (Bombaceae), diameter 55 microns, Eocene, Venezuela.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Isolated Tissues or Cells (Pl. 11-I, fig. 18)

Other types of isolated tissues or cells, such as bordered pits and woody tissues, can be used for general age determinations. A detailed knowledge of fossil-plant anatomy is necessary to use these fragments in micropaleontological investigations.

Animal Microfossils

Foraminifera

Foraminifera are small, one-celled animals belonging to the phylum Protozoa. Most of them have calcareous shells (tests), although some of the early and fresh-water forms have only chitinous tests, whereas those living in areas of turbulence often have arenaceous or agglutinated tests. Because foraminifera differ considerably in size, shape, and ornamentation, they have been used extensively to zone various parts of the stratigraphic column. Foraminifera are found in rocks from the early Paleozoic to Recent.

No other group of microfossils has contributed so much to our knowledge of the subsurface as the foraminifera, which have been used by the oil industry for approximately 40 years. All the major oil companies support microfossil laboratories primarily devoted to the use of the foraminifera for stratigraphic purposes. Besides being used extensively in zoning wells and determining the age of sediments, they are important as paleoecological indicators, and therefore help to interpret favorable or unfavorable environments for oil accumulation. Current research in the Gulf of Mexico and Caribbean areas on Recent foraminifera should improve our knowledge of the different habitats that a particular genus, species, or assemblage prefers. This information may be used as an aid for interpreting ancient environments. Because the planktonic (free-floating) forms are facies tolerant and generally widespread, they are especially useful for long-distance correlation.

This discussion will treat separately three types of foraminifera, subdivided mainly on the basis of size. These include: (1) the microforaminifera; (2) the small foraminifera; and (3) the large foraminifera.

Microforaminifera (Pl. 11-III, figs 1-4)

These are the minute forms of foraminifera, which for many years have passed through the fine-mesh screen in oil companies' paleontological laboratories. Only recently they have been noted in residues prepared for the studies of plant spores and pollen. Whereas, foraminiferal studies have been confined by most workers in oil exploration to the small foraminifera whose average size is 500 microns (0.5 mm.), the microforaminifera have size ranges from 50 to 150 microns. Unlike the small foraminifera, the microforaminifera have to be studied under a high-powered microscope rather than under the usual low-powered stereoscopic type.

At the present time little is known about these comparatively newly discovered foraminifera. Since most of these forms have a large initial chamber, it is believed that they may be closely related to the megalospheric generation in the foraminiferal life cycle. The current belief is that these minute foraminifera represent another stage in the life cycle of foraminifera. Not only are the same genera recognized in the microforaminifera as in the small foraminifera, but in some instances, the same species are found in both groups.

It is interesting to note that in the preparation technique employed for the liberation of the microforaminifera, the sample is treated with 52 percent hydrofluoric acid, which, instead of destroying the calcareous tests of these microfossils, changes them from calcium carbonate to calcium fluoride. It is obvious that only those with calcareous tests are preserved, since the hydrofluoric acid would destroy those with siliceous tests.

Small Foraminifera (Pl. 11-III, figs. 5-14)

The small foraminifera have been used more extensively in oil company laboratories and on well sites than the other two types. More is known about them because early workers recognized their stratigraphic value in subsurface studies. No major mechanical difficulty is encountered generally in freeing them from the enclosing sediments. They are used widely for correlation as well as for age determination. Some forms, because of their restriction to certain environments, serve as paleoecological indicators. The planktonic forms are especially useful for long-distant correlation. Because of the extensive literature on small foraminifera, the writer has purposely restricted his discussion of these very important microfossils.

Large Foraminifera (Pl. 11-III, figs. 15-22)

The large foraminifera include such families as the Orbitoididae, Discocyclinidae, Miogypsinidae, and the Fusulinidae. They are commonly found in carbonate rocks, and thin sectioning is generally required for their identification. In the field, a whetstone and a hand lens may be the only tools needed for the general recognition of a particular genus. However, as this group of foraminifera has not been widely studied by oil company paleontologists in this country, the experience of a specialist is often required for positive identification. The fusulines are the largest and most complex of the late Paleozoic foraminifera.

Radiolaria (Pl. 11-IV, figs. 13-16)

Radiolarians are marine Protozoa of long geologic range, supposedly pre-Cambrian to Recent. Their perforated tests are distinguished from other micro-

PLATE 11-III

1—*Bolivina* sp., size 50 x 88 microns, Recent, Atlantic Ocean.

2—*Globigerina* sp., size 45 x 88 microns, Recent, Atlantic Ocean.

3—*Rotalia* ? sp., size 50 x 65 microns, Recent, Atlantic Ocean.

4—*Bolivina* sp., size 37 x 80 microns, Recent, Atlantic Ocean.

5—*Ammodiscus turbinatus* Cushman, size 1.5 mm., Cretaceous, Trinidad. (Cushman, U.S. Geol. Survey, Prof. Paper 206) (after Cushman and Jarvis)

6—*Tritaxia jarvisi* Cushman, front view, size 1 x 2 mm., Cretaceous, Trinidad. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

7—*Quinqueloculina moremani* Cushman, size 0.3 x 0.5 mm., Cretaceous, Texas. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

8—*Robulus navarroensis* (Plummer) Cushman var. *extruatus* Cushman, size 1.6 mm., Cretaceous, Texas. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

9—*Dentalina gracilis* D'Orbigny, size 1.3 mm., Cretaceous, Texas. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

10—*Gumbelina globocarinata* Cushman, size 0.4 mm., Taylor marl, Cretaceous, Texas. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

11—*Pseudouvigerina seligi* (Cushman) Cushman and Todd, size 0.3 mm., Arkadelphia marl; Cretaceous, Arkansas. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

12—*Bulimina arkadelphiana* Cushman and Parker, size 0.7 mm., Arkadelphia marl, Cretaceous, Arkansas. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

13—*Globotruncana canaliculata* (Reuss) Cushman, size 0.6 mm., Cretaceous, Bavaria. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

14—*Globorotalia membranacea* (Ehrenberg) White, size 0.4 mm., Velasco shale, Cretaceous, Mexico. (Cushman, U.S. Geol. Survey, Prof. Paper 206)

15—*Camerina striatoreticulata* (L. Rutten) Cole, median section, size 4.8 mm., Eocene, Panama. (Cole, U.S. Geol. Survey, Prof. Paper 244)

16—*Camerina striatoreticulata* (L. Rutten) Cole, transverse section, size 2 x 5.6 mm., Upper Eocene or Lower Oligocene, Panama. (Cole, U.S. Geol. Survey, Prof. Paper 244)

17—*Lepidocyclina (Lepidocyclina) canallei* Lemoine and R. Douville, equatorial section, size 3 mm., Oligocene, Panama. (Cole, U.S. Geol. Survey, Prof. Paper 244)

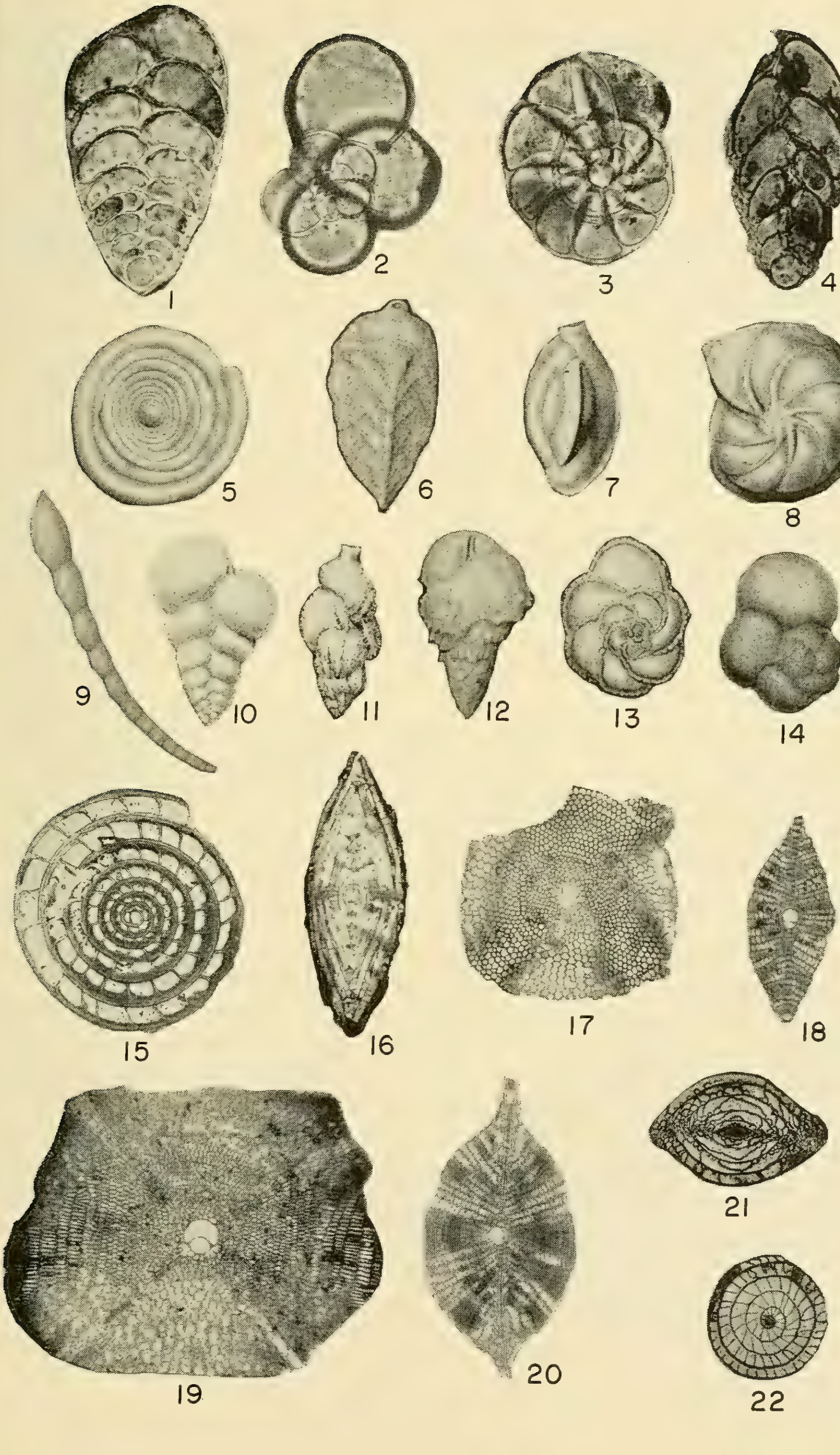
18—*Lepidocyclina* (*Lepidocyclina*) *canallei* Lemoine and R. Douville, transverse section, size 1 x 2.6 mm., Oligocene, Panama. (Cole, U.S. Geol. Survey, Prof. Paper 244)

19—*Asterocyclina minima* (Cushman) Cole, equatorial section, size 2.5 mm., Eocene, Panama. (Cole, U.S. Geol. Survey, Prof. Paper 244)

20—*Asterocyclina minima* (Cushman) Cole, vertical section, size 1 x 2 mm., Upper Eocene, Cuba. (Cole, U.S. Geol. Survey, Prof. Paper 244)

21—*Paraschwagerina yabei* (Staff) Thompson, axial section, size 6 x 9.5 mm., Permian, Sicily. (Thompson, Univ. Kan. Paleont. Contrib. No. 4)

22—*Paraschwagerina yabei* (Staff) Thompson, sagittal section, size 6.5 mm., Permian, Sicily. (Thompson, Univ. Kan. Paleont. Contrib. No. 4)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fossils by their composition of silica or strontium sulfate. The tests are spheroid, asteroid, or bell-shaped. Because there are numerous types of radiolarians with very similar shapes, it is often difficult to distinguish species. Radiolarians, being pelagic, are especially useful for long-distant correlation.

Calpionellidae

The Calpionellidae are small (25-50 microns) calcareous, uniloculur, cup-shaped forms found in Upper Jurassic-Lower Cretaceous limestones, and are probably related to the Tintinnoidea.

Porifera (Pl. 11-I, figs. 23-26)

Needle-shaped and stellate calcareous or siliceous sponge spicules, averaging a few millimeters in length, are found in rocks from pre-Cambrian to Recent. Although they are not used widely in economic paleontology, they should be useful in microfossil work when better understood.

Alcyonarian Spicules (Pl. 11-I, figs. 27, 28)

Alcyonarian spicules are the microscopic calcareous or horny skeletal remains of some of the alcyonarian corals. They occur in Upper Cretaceous and Tertiary sediments.

Echinodermata

The sketetal elements of the holothurians, known as sclerites (Pl. 11-I, figs. 29-32), have forms such as plates, wheels, hooks, ladles, and anchors. These microfossils and the echinoid spines promise to become useful to the micropaleontologist when they are more thoroughly understood. The Echinodermata are marine animals with a geologic range extending from Ordovician to Recent.

Ostracodes (Pl. 11-IV, figs. 1-5)

Although ostracodes are not used in correlation work as extensively as the foraminifera; however, they are being used for age determinations and for paleoecological interpretations. They are small, bivalved Crustacea, occurring more abundantly in marine environments than in fresh and brackish waters, and range from 0.5 to more than 20 millimeters in length. The two valves, generally unequal in size, usually can be distinguished as right and left. Ostracodes are found in rocks of the Ordovician to Recent.

The ostracodes are especially useful in the nonmarine beds where foraminifera and other marine microfossils are absent, and are found most commonly in shales, marls, and limestones. Because many genera and species have restricted geological ranges and wide areal distribution, they serve as index markers and as paleoecological indicators.

Ostracodes are abundant in early Paleozoic rocks where foraminifera and plant spores are absent and, therefore, are especially useful in correlating these early sediments.

Other Arthropoda

The disarticulate exoskeletal remains of other arthropods are found in sediments dating to the pre-Cambrian. Many arthropod fossils encountered in amber are so well preserved that a detailed study of the spines and hairs is possible. Insect wings and other body elements have been found in perfect condition in shales. An extinct group, the trilobites (Pl. 11-IV, figs. 6, 7) are exclusively marine, and are especially abundant in the early Paleozoic rocks.

Scolecodonts (Pl. 11-IV, fig. 12)

The scolecodonts are worm jaws composed of a chitinous, horny substance. They are found in brackish to marine sediments and have a geologic range from Ordovician to Recent. These minute fossils (50 microns-5 mm.) are not used as extensively by the economic paleontologist as are the conodonts, partly because the forms show little change through geologic time. Although they resemble the conodonts, they are different in their chemical composition and probably have different biological affinities.

Conodonts (Pl. 11-IV, figs. 8-11)

Branson and Mehl (1944) described the order Conodontophoridia as "minute toothlike objects ranging in shape from simple recurved cones, through denticulate bars and blades, to highly specialized platforms; having either fibrous or laminated internal structure; comprised of calcium phosphate; and attached to fragments of similar composition assumed to have been jaws. (L. Ord.—Perm; Mesozoic?)."

Conodonts are extremely valuable as index markers in Paleozoic rocks. These peculiar, minute, toothlike microfossils range from Ordovician to Triassic. They vary in size from 100 microns to over 2 mm. Conodonts differ chemically from scolecodonts, in that they are composed of calcium phosphate rather than chitin and silica. Often conodonts can be differentiated from the black scolecodonts by their amber to light-brown color. Because of their chemical composition, conodonts are destroyed by hydrochloric acid, but they can be liberated from carbonate rocks by treatment with acetic or citric acid.

The wide distribution of conodonts leads some workers to believe that they are remains of unknown pelagic organisms, and if this is so, they should be valuable for long-distance correlations.

PLATE 11-IV

1a,b—*Beyrichia triberculata* (Kloden) Boll., (a) Lateral view of female right valve 2.9 mm.; (b) Lateral view of male right valve 2.9 mm.; Silurian, Europe. (Kesling, Contr. Mus. Paleontology, v. 8)

2—*Howella ichinata* Puri, lateral view, left valve, size 0.72 mm., Miocene, Florida. (Puri, Jour. Paleontology, v. 30, no. 2)

3—*Paracytheretta multicarinata* Swain, lateral view of left valve, size 0.6 mm., Recent, San Antonio bay, Texas. (Swain, Jour. Paleontology, v. 29, no. 4)

4a, b—*Procytheridea crassa* Peterson, (a) left lateral view female carapace; (b) dorsal view female carapace; size 0.66 mm., Jurassic, Wyoming. (Peterson, Jour. Paleontology, v. 28, no. 2)

5a, b—*Howella echinata* Puri, (a) exterior view of right valve; (b) interior view of left valve; size 0.75 mm., Miocene, Florida. (Puri, Jour. Paleontology, v. 30, no. 2)

6—*Heliomeroides teres* Evitt, size 1.6 x 3.6 mm., lower Lincolnshire limestone, Middle Ordovician, Virginia. (Evitt, Jour. Paleontology, v. 25, no. 5)

7—*Sphaerexochus hapsidatus* Whittington and Evitt, size 1.4 x 2.5 mm., lower Lincolnshire limestone, Middle Ordovician, Virginia. (Whittington and Evitt, Geol. Soc. America, Mem. 59)

8—*Palmotolepis* sp., size 0.83 x 1.4 mm., Upper Devonian, New York. (Hibbard, Paleontological Laboratories, Buffalo, N. Y.)

9—*Bryantodus radiatus* (Hinde), size 0.6 x 1.3 mm., Upper Devonian, New York. (Hibbard, Paleontological Laboratories, Buffalo, N. Y.)

10—*Polygnathus ordinatus* Bryant, size 0.4 x 1.7 mm., Upper Devonian, New York. (Hibbard, Paleontological Laboratories, Buffalo, N. Y.)

11—*Polygnathus linguiformsis* Hinde, size 0.8 x 2.1 mm., Devonian, New York. (Hibbard, Paleontological Laboratories, Buffalo, N. Y.)

12—Scolecodont (*Oenonites* ?), size 35 x 100 microns, Silurian, New York.

13—*Astractura ordinati,* diameter 220 microns, Miocene, Trinidad.

14—*Lamprocyclas maritalis,* size 148 x 254 microns, Recent, India.

15—*Heliodiscus humboldti,* diameter 280 microns, Miocene, Barbados.

16—*Haliomma oculatum,* diameter 148 microns, Miocene, Haiti.

17—Discoasterid, diameter 22 microns, Miocene, Sumatra.

18—*Leiosphaera* sp., diameter 48 microns, Devonian, Canada.

19—*Hystrichosphaeridium* sp., diameter 38 microns, Devonian, Canada.

20—*Hystrichosphaeridium* sp., body diameter 25 microns, length of spines 25 microns, Upper Ordovician, Iowa.

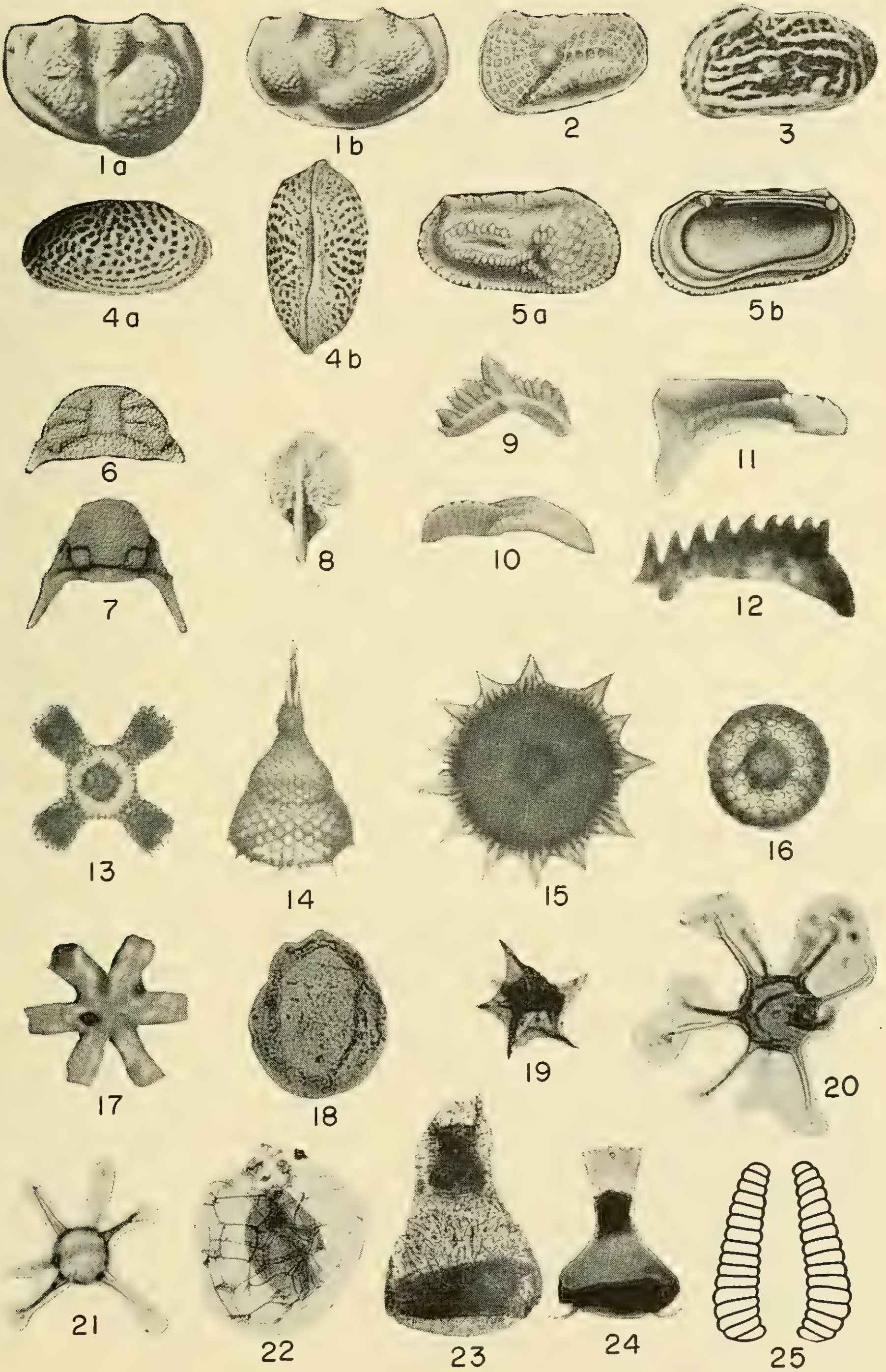
21—*Hystrichosphaeridium* sp., body diameter 16 microns, spines 21 microns, Upper Ordovician, Iowa.

22—*Cannosphaeropsis* sp., body diameter 42 x 65 microns, overall size 80 x 90 microns, Miocene, Virginia.

23—*Angochitina* sp., size 65 x 105 microns, Devonian, Canada.

24—*Ampullachitina* sp., size 85 x 115 microns, Middle Silurian, New York.

25—*Nannoconus colomi* (Lapparent) Kamptner, size 15 x 20 microns, Upper Jurassic — Lower Cretaceous, Mediterranean region (Traite de Paleontologie, Tome Premier, 1952)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Microfossils of Uncertain Affinity

Discoasteridae (Pl. 11-IV, fig. 17)

The Discoasteridae are minute, stellate, calcareous structures with shapes ranging from radially-ribbed, imperforate plates to starlike bodies consisting of 4 to 8 arms. They are found in Cretaceous and Tertiary marine rocks, and are probably the skeletal remains of extinct, unknown planktonic microorganisms. Like the calcareous microforaminifera, they are found also in the residues prepared for plant spores and pollen. When treated with 52 percent hydrofluoric acid, their tests change from calcium carbonate to calcium fluoride. When more is known about the discoasterids they should be useful in paleontological laboratories.

Hystrichospherids (Pl. 11-IV, figs. 18-22)

The hystrichospherids, a group of microfossils of unknown biological affinities, are becoming an important tool in oil exploration. These minute fossils have been recognized in rocks ranging from the pre-Cambrian to Recent. Little is known of the hystrichospherids except that they occur in brackish to marine sediments, and, therefore, are important as paleoecological indicators. Early workers such as Ehrenberg in 1836 thought they were fresh-water algae. Merrill in 1895 considered them to be sponge spicules, while Lohman in 1904 compared them with the spring eggs of marine planktonic crustacea. In 1933, Wetzel described them as remains of unknown organisms related to the dinoflagellates.

Though many hystrichospherids are simple spheres or elliptical structures, others have morphological characteristics such as spines, which make them diagnostic and easily recognized. Their most frequent occurrence is in shales, cherts, limestones, and dolomites; but they are also found in siltstones and sandstones. To the stratigrapher, hystrichospherids are especially useful in the Lower Paleozoic rocks where other microfossils often are scarce or absent. The preservation of hystrichospherids is frequently very complete, and because of their minute size they can be recovered from well samples where other microfossils are destroyed.

In general, many Lower Paleozoic forms are minute, smooth, spherical-to-elliptical bodies belonging to the genus *Leiosphaera.* Middle Paleozoic forms have spherical to triangular bodies with large simple spines or arms that attenuate from the central body. The Upper Paleozoic hystrichospherids generally have larger central bodies, which are smooth or covered with many sharp spines. The genus *Hystrichosphaera,* whose vesicle wall consists of plates, is characteristic of the Mesozoic. *Cannosphaeropsis,* a genus with the processes branching and joined at the tops, thereby forming a netlike cover around the vesicle, is found in the Mesozoic and Tertiary. There is also some evidence that it may extend into the Recent. The genus *Hystrichosphaeridium* is most common in the Cenozoic, although it occurs in the Mesozoic and Paleozoic as well.

In summary, several factors emphasize the usefulness of the hystrichospherids to petroleum geologists: (1) they are found in rocks from pre-Cambrian to Recent; (2) they show characteristic differences between rocks of different ages; (3) they show differences in form with respect to their relative distance from reefs or ancient shores; and (4) they are found in many different lithologies.

Chitinozoa (Pl. 11-IV, figs. 23, 24)

As the name implies, the Chitinozoa are composed of chitinous material. They occur in marine sediments as hollow membranes in various forms such as tubes, flasks, urns, funnels, and bells. Their biological affinity is not known. Because of their occurrence in early Paleozoic rocks (Cambrian-Mississippian), they are especially valuable to the stratigrapher in the study of Cambrian and Ordovician sediments that usually are void of other microfossils.

Nannoconus (Pl. 11-IV, fig. 25)

Another form of uncertain affinity is *Nannoconus*. These rock-forming, minute calcareous organisms (size range 100-180 microns) are found in Jurassic and Cretaceous marine sediments. They are cone-like, consisting of many wedge-shaped elements built around a central canal. Their wide geographic distribution and restricted stratigraphic range make them useful. Bronnimann (1955) has used them successfully in zoning Lower Cretaceous limestones in Cuba.

Oligostegina

Small, rock-forming calcareous spheres (size 50 microns +) known as *Oligostegina* are found in Cretaceous rocks. Early workers thought they belonged to the foraminifera, but the affinity of these small pelagic forms remains in doubt.

Fragmenta

Unidentified spheres, spines, plates, tubes, and other remains frequently occur in prepared residues. These microscopic fossils probably represent elements from unfamiliar animals and plants. Future work on these unknown microfossils undoubtedly will establish their relationships and perhaps they may prove to be useful stratigraphic markers.

SUMMARY

The oil companies are viewing with interest the growing importance of micropaleontological analysis, which includes the study of all types of minute fossils. Through improved recovery techniques, and the recent trend toward studying plant microfossils as well as animal microfossils, the barren sample is fast disappearing. Microfossils are found in practically all types of sediments including salt and continental red beds. Much useful information can be obtained by a careful study of the composite fossil assemblage.

Much advancement in oil-field paleontology has been made since Udden (1914) pioneered the study on some micropaleontological features of well cuttings from Illinois. Only a few paleontologists at present are qualified to work with all the various groups of microfossils mentioned here. A working knowledge of spores, pollen, hystrichospherids, and foraminifera is most desirable. Among the various groups of microfossils, those which are acid-insoluble, seem to be the most promising for future oil-exploration studies.

In conclusion, the factors that make microfossils useful in subsurface work may be summarized as follows:

1. They are found in practically all types of sedimentary rocks ranging from pre-Cambrian to Recent, and because of this, are extremely valuable for determining the age of sediments. Experience has shown that in many instances the age of the rocks can be established within epoch level on a world-wide basis.

2. Because of their small size, they escape destruction by drilling abrasion.

3. Only a small amount of sample is required for examination. In addition, extraction or washing techniques require little time and no elaborate equipment.

4. Microfossils are generally good environmental indicators and thus can be used to separate the favorable areas from the unfavorable areas for oil exploration.

5. As paleontological studies progress, more and more types of microfossils should prove their usefulness to the economic paleontologist.

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Chapter 12

CORE ANALYSIS

J. G. Crawford

The economic production of oil or gas demands a knowledge of the three factors that influence the potential, life, and productivity of the reservoir. These factors are: (1) the characteristics of the reservoir rock; (2) the characteristics of the subsurface fluid; and (3) the type and efficiency of the drive mechanism. Core analysis, electric logs, radioactive logs, and drill-stem tests, together with special studies and areal correlation, give an insight into the first factor; fluid samples taken under reservoir conditions of pressure and temperature and liberated under controlled laboratory procedures give subsurface fluid characteristics; pressure history, production history, gas-oil ratios, and other field tests point to the type of drive and estimate its efficiency.

Core analysis is perhaps the most important tool in the determination of reservoir rock characteristics, but it is only one of the many tools available for the determination of the type of production prior to completion of the well. The electric and radioactive log, the drill-stem test, the core analysis, are all working tools for well completion. For many reasons, any one particular tool may fail to give positive results, but it is doubtful that all three will fail in the same well.

Core analysis, in addition to being an important tool in well completions and the most important tool for reservoir rock characteristics, lends itself admirably to specific and special tests, such as connate water, relative permeability, acid solubility, and flood pot, among others, from which productivity, secondary recovery, and well treatment can be deduced.

SAMPLING OF CORES

The core should be sampled with the thought in mind of obtaining representative data and true net pay thickness. The general custom in the industry is to sample every foot of cored section, and more often if a visible change in characteristics occurs. The samples are marked or labeled as to interval or depth from which obtained, and preserved for transportation to the laboratory.

The two most commonly used methods of preservation of core samples consist of canning or sealing in plastic bags and quick freezing with dry ice. Either method will preserve the fluid content of the sample, and it is obvious that the rock characteristics will not be changed when sealed in air-tight containers. The freezing process has been subjected to criticism by the claim that some of the basic characteristics of the core, e.g., porosity and permeability, are altered during the freezing and thawing cycle.

TYPES OF CORE ANALYSIS

Core analysis is grouped into three categories: (1) small plug or routine analysis; (2) full diameter or special analysis; and (3) all other general and specific tests not of a routine nature.

Routine or plug analysis consists of determinations for porosity, permeability, and fluid saturation utilizing ¾-inch or 1-inch plugs drilled from the core. This method has proved satisfactory for homogeneous material such as unfractured sandstones and limestones but is limited to analysis of matrix characteristics due to inability to incorporate cracks and fractures in the specimen.

Full diameter analysis was developed to overcome the deficiences of plug analysis. This technique analyzes the entire core, cut or broken to convenient lengths. The influence of vugs, cracks, and fractures on the basic characteristics of the rock is thus measured, as both matrix and fracture porosity and permeability are included in the test specimen.

General core analysis consists of all special tests that do not involve routine porosity, permeability, and fluid saturations. This category includes capillary pressure curves, connate water determinations, flooding tests, acid solubilities, pore-size distribution, grain-size distribution, and similar and related analyses.

METHODS OF ANALYSIS

Porosity

The most important function of a reservoir rock is its storage capacity, or porosity. This factor determines the quantity of fluid that a rock can hold, and though permeability or fluid movement may be induced by various means, the storage capacity of a reservoir is fixed and unvarying even though the distribution of the fluids therein may be alterable. An acre-foot contains 7758 barrels; thus each porosity percent has storage capacity for 77.58 barrels of fluid under reservoir pressure and temperature conditions.

All rocks have porosity. The pore space may be extremely small in dense rock and unfavorable for production; it may consist of interstices between sand grains that will range as high as 40 percent of the bulk volume; it may be vugs and cavities ranging from pin point to thumb size; it may be cracks and fractures that form an inter-communicating network extending for long distances; it may be any, or a combination of these.

There are two types of porosity—absolute total and effective. A rock may have pore space that has been filled with fluid and subsequently sealed from other pores by deposition of secondary minerals; in which instance, some of the pores do not communicate. Yet this is pore space that can be measured by reducing all the bulk to individual grains, breaking down and rupturing the walls of the sealed portions. Porosity thus determined is called absolute or total porosity. The oil industry, however, is interested in producible porosity—that porosity in which the pores communicate, regardless of how tortuous the path of communication might be. This type of porosity is called effective, and may range from as low as 10 percent to 100 percent of the absolute.

Table 12-I was prepared from an average of approximately 400 individual specimens. These specimens had been analyzed over a period of years for both types of porosities. Both limestones and sandstones are represented, and the steadily increasing ratio of effective to total porosity is clearly illustrated.

The pore space in a rock may be calculated by the relationship of its bulk volume to either its grain volume or its pore volume, as follows:

$$\%\ \text{porosity} = 100 \times \frac{\text{bulk volume} - \text{grain volume}}{\text{bulk volume}}$$

$$\%\ \text{porosity} = 100 \times \frac{\text{pore volume}}{\text{bulk volume}}$$

The actual laboratory measurement of porosity is performed by determining: (1) the bulk volume of the specimen; and (2) either the grain volume or pore volume of the same specimen. The particular method to be adopted

TABLE 12-I

*Comparison of Effective to Total Porosity
(By laboratory measurement)

Effective Porosity (Percent)	*Total Porosity (Percent)*	*Ratio Effective to Total*
0.2	1.4	0.143
0.3	1.3	0.231
0.5	1.8	0.278
0.8	1.9	0.421
1.0	2.3	0.435
1.5	2.7	0.556
2.0	3.6	0.556
2.5	3.3	0.758
3.0	3.9	0.769
5.0	6.0	0.833
7.0	7.5	0.933
10.0	10.3	0.971

*Averages of 20 to 40 samples each porosity.

depends on the type of rock to be tested, the number of analyses to be made, and the degree of accuracy required.

Determination of Bulk Volume

It is preferable to use the same specimen for both porosity and permeability measurements. The sample is prepared by drilling a cylindrical plug approximately 1 x 1 inches parallel to the bedding plane of the core, or by sawing a cube of the same dimensions. The cube has one advantage over the plug in that the vertical permeability can be determined on the same specimen by simply rotating the cube in the holder. The sample, whether cylinder or cube, is cleaned of oil by extraction with suitable solvents in a Soxhlet or any of the pressure and centrifugal types developed by the various core laboratories for the rapid extraction of oil. Toluene, benzene, benzene-alcohol mixtures, pentane, and other solvents are suitable; chloroform and carbon tetrachloride are not recommended because of the possibility of hydrolysis resulting in the production of acids. The sample is then dried under infra-red lamps or in an electric oven, and cooled in a moisture-free atomsphere.

(1) Bulk-Volume Determination By Submergence of a Saturated Sample

The extracted and dried samples are placed in a wide-mouthed jar closed with a rubber stopper fitted with a two-way stopcock. One side of the stopcock is connected to a vacuum pump and the other to a funnel containing the saturant. The jar and samples are evacuated and the stopcock turned to admit the saturant to cover the samples completely. Air is then admitted to bring the pressure to atmospheric. After saturation, the samples are taken from the jar; the excess liquid is removed by touching the sample to a filter paper; and the volume of saturant displaced by the saturated sample is determined in a pycnometer. Many different liquids have been suggested and used for this purpose, but it has been found that kerosene is satisfactory and is usually easy to obtain and less expensive than other liquids.

(2) Bulk-Volume Determination By Displacement With Mercury

Presaturation of the sample can be avoided by submerging the specimen just below the surface of mercury and measuring the displaced mercury. A pycnometer having a cap with a ground taper and a small hole drilled through the cap is filled with mercury; the cap is inserted; and the excess mercury that overflows is collected and set aside. The cap is removed, the sample placed on the surface of the mercury and submerged by a short set of rods on the underside of the cap, and the reseating of the cap causes overflow of a quantity of mercury equivalent to the bulk volume of the sample. This mercury is collected and measured. Available commercial types of apparatus that determine the rise of the mercury level by electrical contacts or hydrostatic connections are less time consuming than the pycnometer; apparatus of this nature is calibrated by steel balls or slugs, and the volume is read directly on a curve.

Another method involves the determination of the dry weight of the sample and the weight necessary to submerge it in mercury. The sample is submerged with pointed steel rods, and the weight required to submerge the rods alone to the same depth is determined. The bulk volume is calculated by dividing the sum of the dry weight and the weight required to submerge the sample, less the weight required to submerge the rods, by the density of the mercury.

(3) Bulk-Volume Determination By Calipering

The cylindrical sample with ends squared by a diamond saw, or the cube, is admirably suited to linear measurement and arithmetical calculation of the bulk volume. Calipers, micrometers, or similar instruments are used to measure the average diameter and length of the sample, and the volume is read from prepared tables. A dial comparator, though expensive, is remarkably rapid and accurate for these measurements.

The above are the preferred methods of bulk-volume determination. Obviously, the type of sample to be tested and the number of analyses will influence the method to be used. Calipering is more universally adaptable than submergence or displacement, but it cannot be used with irregular specimens or loosely consolidated sandstones that sluff easily. Submergence, though somewhat more time consuming than the other methods, has the advantage that it can be applied

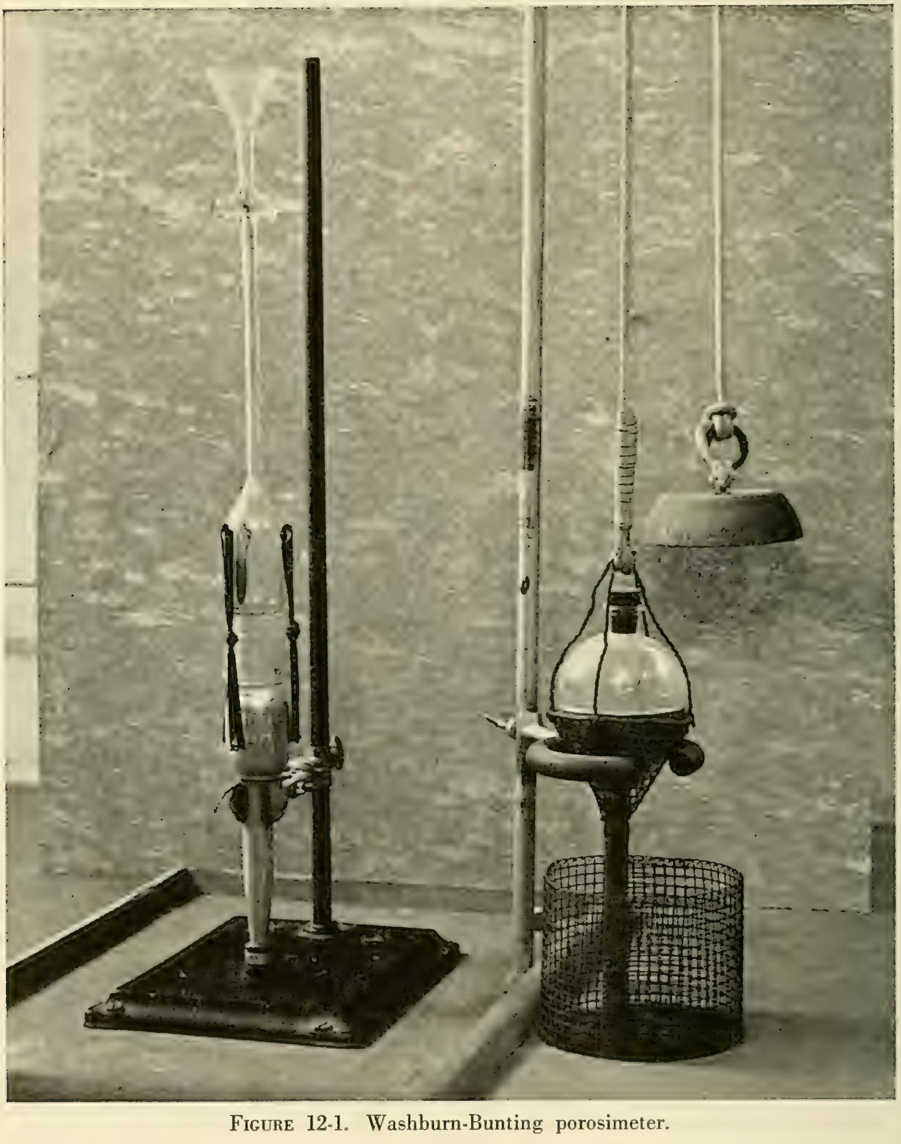

FIGURE 12-1. Washburn-Bunting porosimeter.

to loosely cemented and irregular samples: it is also one of the best available methods with which the porosity of small fragments or drill cuttings can be obtained. Displacement is a more rapid procedure than submergence, and irregular samples can be measured, but high porosity samples have a tendency to absorb enough mercury to reduce materially the pore space for subsequent pore-space or grain-volume measurements. Calipering is the most rapid method of bulk-volume determination. It is readily adapted to any type of rock that can be drilled or cut to definite size and is the only method available for vuggy material in which the larger vugs on the exterior surface of the specimen are an integral part of the pore space.

Determination of Pore Volume

(1) Measurement of Pore Volume By the Washburn-Bunting Porosimeter

This instrument (fig. 12-1) is very popular in many laboratories in which a large number of samples are handled daily. It is the most widely used of that class of porosimeters in which the sample is evacuated and the air trapped and measured. The sample is placed on the surface of the mercury in the enlarged portion of the instrument; the upper half is firmly seated with a ground-glass joint; and the mercury is raised to completely surround the sample and fill the graduated portion to and just slightly above the stopcock, which is then closed. The mercury column is lowered 3 or 4 feet below the sample chamber for a definite period of time, then raised to trap the air in the graduated neck. The mercury columns are balanced and the volume of trapped air, minus a predetermined correction factor, is the pore volume of the sample.

(2) Measurement of Pore Volume By Mercury Injection

This is another rapid and popular method of pore-volume determination used by several laboratories when a large number of samples are to be processed. The mercury porometer (fig. 12-2) is an expensive instrument but combines both bulk-volume and pore-volume measurements in one operation. In principle the instrument is a high-pressure mercury pump calibrated in cubic centimeters per turn and fitted with a sample chamber that can be vented to the atmosphere. The bulk volume of the sample is measured by the difference between the volume of mercury required to fill the empty chamber and the volume required to fill the chamber and sample at atmospheric pressure. The vent is then closed, and the chamber and sample are pressured to a predetermined arbitrary reading. The volume of mercury forced into the sample, suitably corrected for compressibility, is the pore volume.

Determination of Grain Volume

(1) Measurement of Grain Volume By Determination of the Grain Density

The extracted and dried sample is weighed and saturated with a liquid, and the weight of the saturated sample while immersed in the same liquid is determined. The grain volume is equal to the difference between the dry weight and the saturated submerged weight divided by the density of the saturant. An alternative method, used primarily to estimate or check on the measured

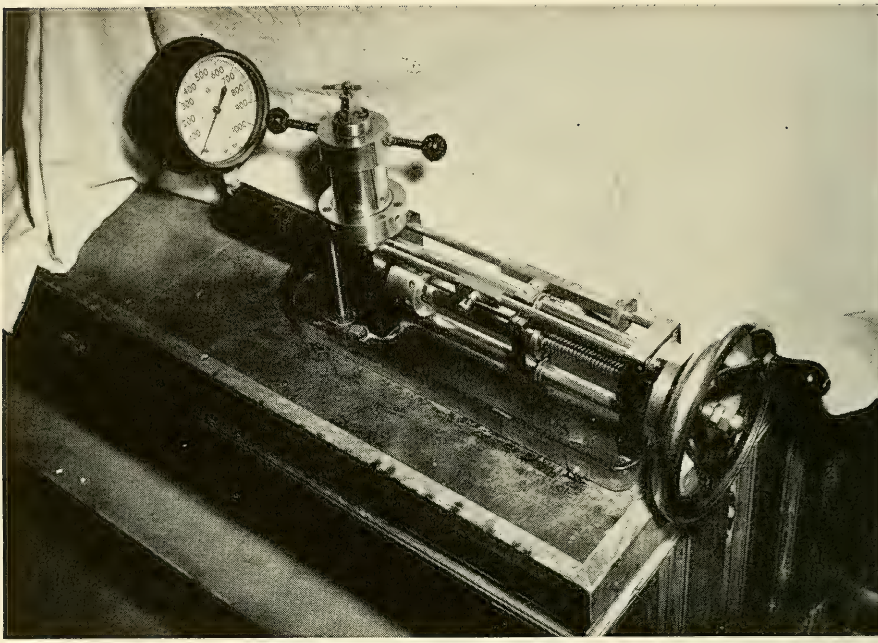

FIGURE 12-2. Mercury porometer.

porosity of a sample, is to divide the dry weight of the specimen by an assumed matrix density to find the grain volume. Matrix densities that are in reasonable agreement with true densities are 2.65 for sandstones, 2.72 for limestones, and 2.86 for dolomites.

(2) Measurement of Grain Volume By Gas Displacement

The extracted and dried sample is placed in a steel chamber that is filled with gas to a specific pressure. The gas in the chamber is then expanded into a burette at atmospheric pressure and measured—or, as an alternative, into an expansion chamber and the new pressure in the system measured. The volume of gas, or system pressure, obtained by expansion from the sample chamber containing the specimen is compared to the same measurement with the sample chamber empty. The volume of gas displaced, or the increase in system pressure, due to the sample is a measure of grain volume. For rapidity of measurement, calibration curves are prepared. Instruments (fig. 12-3) operating on this principle are available commercially, or can be constructed at relatively low cost.

(3) Measurement of Grain Volume By Pycnometer

The sample need not be extracted or dried for this procedure. A specimen is broken from the core and the bulk volume determined by any of the procedures

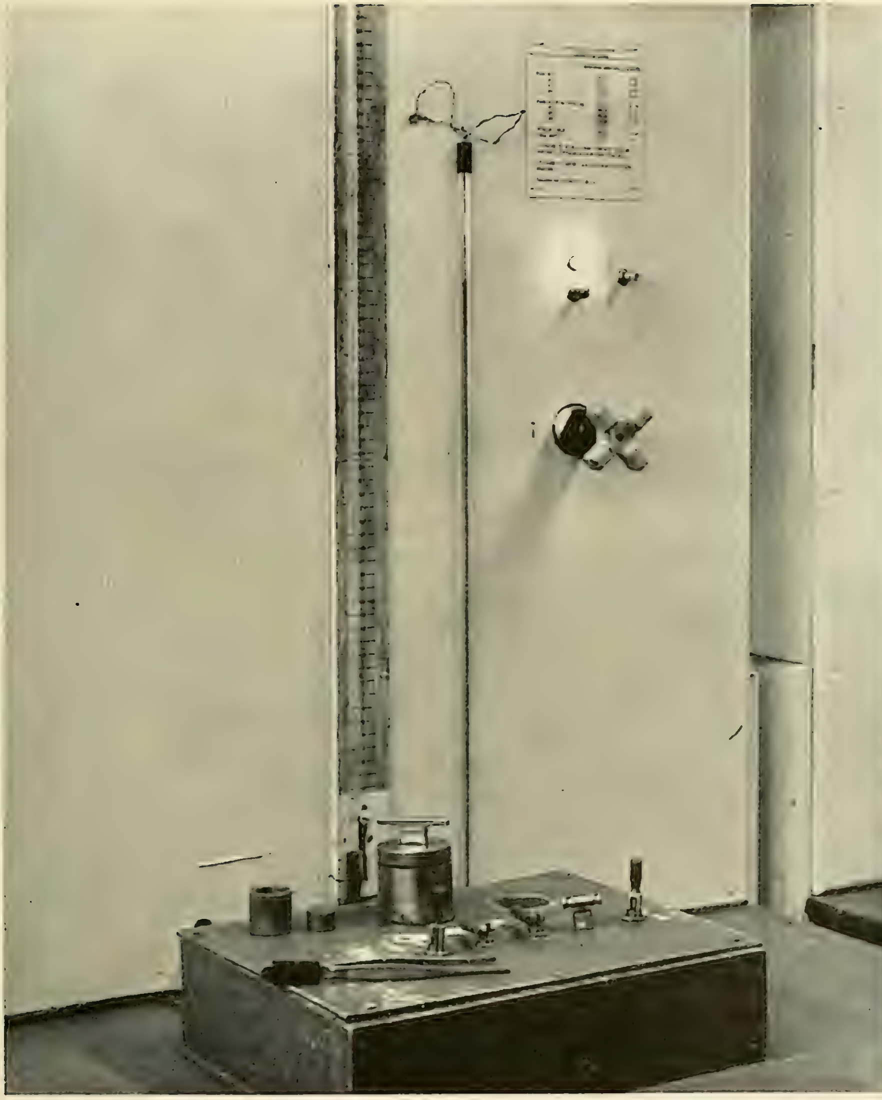

FIGURE 12-3. Boyle's law or gas-expansion porosimeter.

given herein. The specimen is then crushed to its individual grains, washed free of oil by any satisfactory solvent, and dried: and the volume of the grains is measured in a pycnometer with any suitable liquid. The porosity thus determined, of course, is total porosity, whereas the other methods described herein measure effective porosity.

Summary Comments

The above methods are all approved procedures, and other types of apparatus are usually variations or combinations of these. It is recommended that porosity and permeability measurements be made on the same specimen; thus the cube or cylindrical plug is usually prepared and the bulk volume determined by calipering as the L/A factor is immediately available. Effective porosity is almost always determined, there being little or no demand for absolute porosity. Criticism can be leveled against all current methods of pore-space determination, and none of these methods can satisfy rigid requirements for accuracy in all ranges of porosity, but they are the methods that have survived the test of time and *judged* within the tolerances of good porosity determination.

Permeability

Permeability is a measure of the capacity of a porous medium to transmit fluids. The unit of permeability is the darcy, which is defined as follows: A porous medium having a permeability of one darcy will, under conditions of viscous flow, transmit 1 milliliter per second of a fluid of 1 centipoise viscosity through 1 square centimeter cross-section when a pressure gradient of 1 atmosphere is applied. The commonly used unit is the millidarcy (0.001 darcy) (md).

The fundamental assumption of permeability is that as long as the flow is viscous, the permeability of a porous medium is a property of the medium and independent of the fluid used in its determination, and the same numerical value should be obtained regardless of fluid used. Liquids, however, usually interact with the rock material, and the numerical value of permeability by liquid measurement is almost invariably lower than the value as measured with a gas. It is also obvious that the presence of any liquid in the rock will have an adverse effect on the measurement of permeability by any other fluid. Thus, permeability measured with a dry gas on a clean and dried specimen of rock is the maximum that can be obtained and is called absolute permeability and designated by K.

When the saturation of a particular fluid in the porous material is less than 100 percent of the pore space, the permeability of the material to that fluid is known as the effective permeability and is written with a subscript as Ko, Kg, or Kw. The ratio of the effective permeability at a definite saturation to the permeability at 100 percent saturation is termed relative permeability, and designated as Kg/k, Kw/k, or Kg/Ko. Effective and relative permeability will vary from a value of zero at some low saturation of the fluid to a value of 1.0 at 100 percent saturation of that fluid.

Effective and relative permeabilities are concepts of interest to the reservoir engineer. The permeability determined as a routine factor in core analysis work is absolute. It is measured parallel to the bedding plane by using dry air through a clean, dry-rock specimen.

Permeability Formulas

The standard permeability formula is:

$$K = \frac{uQL}{A\ (P_1 - P_2)}$$

K = Permeability, darcies
u = Viscosity of fluid (cp)
L = Length of plug (cm)
A = Area of plug (cm^2)
P_1 = Upstream pressure (atm)
P_2 = Downstream pressure (atm)
Q = Flow in center of core at mean pressure, ml/sec.
Q' = Flow at downstream face of core at pressure P_2, ml/sec.

When Q is measured with an incompressible liquid, Q and Q' are numerically equal, and the formula becomes

$$K\ (in\ md) = CuQ' \frac{L}{A} \quad where\ C = \frac{1{,}000}{P_1 - P_2}$$

C can be made into a series of constants by setting P_1 at selected gauge pressures and using the average barometric pressure as P_2.

Gas is compressible, and the Q in the fundamental formula refers to the flow in the center of the core at mean pressure. This flow cannot be measured directly, but the flow Q' at the downstream end of the core is measured and translated to Q by means of Boyle's law. Thus, the standard permeability formula when a gas is used as the measuring medium becomes

$$K\ (in\ md) = CuQ' \frac{L}{A} \quad where\ C = \frac{2uP_2\ (10)^3}{(P_1 + P_2)\ (P_1 - P_2)}$$

Again C can be made into a series of constants to facilitate calculations.

The radial permeability formula introduces r_1 and r_2, the radius of the core and the radius of the central hole respectively, in centimeters; when a gas is used as the measuring medium, the formula becomes

$$K\ (in\ md) = \frac{13.49\ P_2}{(P_1 + P_2)\ (P_1 - P_2)} \times \frac{{}^*\log \frac{r_1}{r_2}}{h} \times Q'$$

*Log to base 10.

Apparatus for the measurement of permeability is usually designed and constructed by the operator, though commercial types are available. They all consist of three basic parts: (1) a means of impressing air on the upstream face of the plug; (2) a method of mounting the specimen to prevent by-passing of the air; and (3) a method of measuring the air flow and pressure at the downstream face of the specimen.

The sample used in the porosity determination, if uncontaminated by this test, or a fresh specimen cut parallel to the bedding plane and cleaned, is mounted in such a way that the sides of the sample are sealed so that a pressure differential can be applied across its length. Cylindrical samples can be inserted in a soft rubber stopper which is forced into a tapered metal holder that compresses the rubber around the specimen; or a Hassler core holder, in which the sample is slipped into a rubber tube and the sides sealed by air pressure on the outside of the tube, can be used. Cubical or irregularly shaped samples can be sealed with wax or plastic. After the sample is mounted, a pressure differential is applied across its length with dry air; and the upstream pressure, downstream pressure, and rate of flow are measured.

The rate of flow can be measured in a number of ways. One of the simplest is the collection of the evolved air in a graduated receiver by displacement of water. Calibrated orifices or capillary tubes are most often used, and these can be arranged so that combinations to cover any rate of flow are available. Other methods utilize the rate of travel of a soap bubble in a vertical tube, or a drop of mercury in a horizontal glass capillary.

The rate of flow must be sufficiently low to avoid turbulent flow. This point should be checked by making a series of determinations with various flow rates and discarding those values that are obviously out of line. It is customary in routine core analysis to maintain a rate of flow within certain predefined limits by manipulation of the upstream pressure to insure viscous range.

Klinkenberg (1941) discussed the phenomena of slip in the measurement of the permeability constant by gases. He pointed out that the discrepancies between air permeability and liquid permeability, where no interaction of rock and fluid occur, were caused by the slippage of gas molecules and that a series of measurements with gas at various average pressures extrapolated to infinite pressure would result in an almost identical permeability constant. This has subsequently been called the Klinkenberg effect. Though recognized, it is in general, ignored by core analysis laboratories on the theory that permeabilities are in a large measure relative and used principally for comparison; also, the Klinkenberg effect is serious in the low permeability ranges only, and it is felt that the results do not justify the additional work necessary to determine the correction.

SATURATION

Laboratory procedures for liquid saturation fall into one of two general methods: (1) the retort method, whereby both oil and water are driven from the crushed core by heat; and (2) the extraction method, whereby the liquids are removed from the sample by solvents. Both methods have their advantages and disadvantages. Speed and simplicity favor the retorting of samples, but a higher degree of accuracy and reliability for at least one of the liquids in the core is evident in the use of extraction methods.

Retort Method

One of the principal advantages of the retort method of saturation determination is the fact that both oil and water are recovered simultaneously in a single operation. Retorts vary in capacity, heat application, and condensing methods. Capacities range from approximately 35 to 150 cubic centimeters in volume with vapor outlets at the top as in the familiar cast-iron mercury retort, or at the bottom as in the Ruska or Keltner type. They may be gas-fired or heated electrically. Condensation is obtained by circulation of cold water, or immersion in an ice bath or dry ice-kerosene mixture. There are so many adaptations of retorts, and all appear to serve their intended purpose in a satisfactory manner. The larger capacity—from 100 to 150 cubic centimeters in volume—is considered more accurate as the larger volume of sample increases accuracy, particularly when cores of low or spotty saturation are analyzed. In all retort methods, corrections for loss and hold-up of liquids are applied, and steps are taken to distinguish between interstitial water and water of crystallization.

Extraction Method

Extraction methods which can be done quite accurately, usually consist of analyzing the sample for water, and measuring the total loss in weight on extraction and drying. The quantity of oil present is calculated by subtracting the weight of water from the total loss in weight. The following methods are approved for the determination of water.

Stark-Dean Distillation

This procedure is similar to the sandard A.S.T.M. method of determining water in petroleum products. A crushed sample of the core is transferred to a porous thimble and weighed. The sample is refluxed with toluene, xylene, or other liquid immiscible with water and boiled at 120 to 150C. The water is caught in a calibrated glass trap. After all the water has been removed from the sample, about 2 hours of refluxing, its volume is read, and the thimble containing the sample is extracted in the same apparatus, or in a Soxhlet, until all oil is removed. The weight of the sample converted to volume, and the volumes of water and oil obtained are calculated to percentage of pore space.

Titration Method

The water content of a weighed, crushed sample can be measured by extracting the sample with anhydrous alcohol and titrating with Fischer's reagent. The oil content is determined by weighing before and after extraction and subtracting the weight of the water.

Critical Solution Temperature Method

The water present in the sample is extracted with anhydrous alcohol, and the temperature at which a mixture of equal volumes of kerosene and the alcohol solution becomes clear on heating, or turbid on cooling, is measured. The method is calibrated for the particular brine and crude oil present in the sample, and the volume of alcohol used for extraction is adjusted so that the critical solution temperature falls within a convenient range.

Other less desirable methods include the vaporization of water and absorption with phosphorous pentoxide, and the extraction of oil from a weighed sample of the core by volatile solvents such as pentane and subsequent recovery of the oil by distillation.

Saturation methods most in use are the retort and Stark-Dean distillation procedures. The retort method appears the most popular because of its simplicity and speed and the fact that both oil and water are being measured simultaneously. The Stark-Dean distillation is used when the water content of the sample is of prime importance. All saturation methods now in use are unreliable, even though it is widely acknowledged that the water content may be accurately determined. Their unreliability is no particular detriment in core-analysis interpretation, however, as they are in no sense a measure of actual reservoir conditions.

BULK OR FULL-DIAMETER METHODS

Since 1947 apparatus and methods have been developed in which the entire core, cut or broken to convenient lengths, is used for the test specimen. This type of analysis, called full diameter, special, or bulk analysis, claims greater accuracy and reliability by avoiding the pitfalls of the small test specimen. It is not limited by the diameter of the core and is limited in length only by the type of apparatus; specimens from 8 to 18 inches in length are conveniently handled by this comparatively new technique. The small-plug method is still in universal use for the analysis of sandstones and relatively homogeneous limestones, but it is supplanted to a great extent by full-diameter methods in vuggy, fractured, cracked, and heterogeneous carbonate rock.

Full-diameter methods, in general, parallel routine plug analysis, but they have resulted in the development of two different approaches to the problem of handling large sections of core. In the one method fluid saturations are determined by vacuum retorting of the section to be analyzed, whereas the second method retorts a crushed sample adjacent to the section to be analyzed. Porosity is determined in the one method by saturation of the section after vacuum retorting, whereas in the second method a standard Boyle's law porosimeter of sufficient capacity is used.

The methods differ primarily in the determination of permeability. The one method has introduced the concept of Kmax and Kmin by passing air through the core parallel to its diameter, rotating the core 90 degrees, and making a second reading perpendicular to the first; this process insures that the entire circumference of the specimen has been tested, but it results in two different numerical values for permeability. The second method introduces radial permeability; a hole is drilled lengthwise through the section to be tested; the air is impressed against the outer circumference; and the downstream pressure and flow are measured from the inner hole. This method simulates actual well conditions and gives one numerical value which can be used in calculations involving the permeability constant.

INTERPRETATION OF CORE-ANALYSIS DATA

Well Completion

Core-analysis data for well completion purposes will usually include porosity, permeability, residual oil saturation, and total water saturation. The probable type of production is forecast by the fluid saturation figures and the permeability of the rock. The saturation figures, as reported in the analysis, obviously do not reflect the saturation in the reservoir, and the interpretation of these data must be based upon certain assumptions as to the changes in the fluid content from reservoir to laboratory conditions.

During the coring operations the formation ahead of the drill is partially flushed by mud filtrate, the extent of the flushing action depending upon such factors as the permeability of the formation, excess mud pressure over formation pressure, rate of penetration, and filtrate loss of the coring fluid. The result is a partially flushed core in which an unknown quantity of reservoir fluid has been replaced by an unknown quantity of mud filtrate.

The partially flushed core is then removed from a high-pressure region in the bottom of the hole to a low-pressure region at the surface, where expansion

TABLE 12-II

Comparison of Wyoming Oil-Productive Sand Cored with Water-Base Mud and Crude Oil

	A. Cored with Water-Base Mud				B. Cored with Crude Oil			
			Saturations				*Saturations*	
No.	*Porosity*	*K (md)*	*% Oil*	*% Water*	*Porosity*	*K (md)*	*% Oil*	*% Water*
1	10.5	18	14.7	37.9	15.1	75	41.2	18.7
2	13.0	73	22.2	34.0	11.2	25	60.4	32.5
3	13.4	103	15.8	39.0	15.6	110	37.7	22.9
4	12.9	72	16.6	25.6	14.8	99	26.9	22.8
5	14.0	160	15.3	35.7	12.1	26	48.0	29.7
6	12.8	47	18.6	33.4	14.1	70	38.7	14.8
7	12.9	73	15.1	33.8	12.2	26	27.1	9.1
8	11.0	31	25.0	40.0	13.4	40	43.4	14.1
9	11.0	57	21.5	45.9	15.6	103	41.5	12.6
10	12.6	43	14.4	39.7	14.8	103	46.1	16.1
11	11.1	86	19.2	34.4	12.5	186	31.8	24.9
12	14.2	110	9.9	57.4	12.6	29	23.9	26.2
Av.	12.5	72	17.4	37.2	13.6	74	38.9	20.4

of fluids within the core takes place. In particular, the solution gas in the oil still remaining in the core expands and expels both oil and mud filtrate.

The gross effect of the coring operation is to submit the core to a gas drive and a water drive, though in reverse order. Thus, the assumptions: (1) the core contains the irreducible minimum oil saturation, oil that cannot be produced by any method short of mining; and (2) the difference between 100 percent and the sum of the percentages of residual oil and connate water is theoretically recoverable reservoir oil.

The usual analysis of cores taken with water-base mud as the coring medium will indicate a residual oil content that is interpreted as irreducible, and will indicate a water content that includes both connate water and an unknown quantity of mud filtrate. The use of any other coring medium will also affect the residual fluids. Crude oil, for example, will infiltrate the core just as mud filtrate does, and the resulting analysis will show a high residual oil percentage and a water content that is interpreted as connate. Table 12-II gives an example of a Wyoming sandstone cored with water base mud and the same sandstone in a different well cored with crude oil. The connate water saturation of this sand averages 20 percent.

The interpretation of core-analysis data is influenced by such factors as the coring medium, size of core, permeability, fracturing, lithology, and others not under the control of the analyst. Far more important, though, than any of the above is the previous core history of the field or area and the analyst's experience in the interpretative phase of core analysis. Adherence to generalized rules is inadvisable, but the following suggestions can be applied cautiously to hard-rock areas:

There are no criteria defining a critical water saturation above which oil production cannot occur. A shaly sand or one containing lentils or nodules of shale can have a much higher critical water saturation than a clean quartzitic sandstone; a coarse, permeable sand will have a lower critical water saturation than a fine-grained, tight, silty sandstone, but may actually contain a higher percentage of water due to mud filtrate loss to the formation.

The permeability factor is a useful criterion for water saturation; a higher water percentage can be tolerated with decreasing permeability, and oil production can be forecast from rock of low permeability with comparatively high saturations. A very porous, permeable sand will soak up mud filtrate like a sponge, and a high water saturation need not condemn the well.

The oil saturation figure is acutally more revealing than the water. A marked decrease in oil saturation with but little upward change in water content usually indicates a transition zone or the actual water table. This applies only to cores taken with water-base mud.

Residual oil saturations in oil-producing rock will range from 5 to 10 percent for high-gravity, volatile crudes; 14 to 24 percent for average crudes; and 30 to 45 percent for heavy, viscous crudes.

A low to a trace of oil saturation with normal water content usually indicates gas production. Fractures extending into the water table, regardless of the oil-productive possibilities of the reservoir, will almost invariably result in water production.

Gas-oil and oil-water contacts are illustrated by the core analysis shown in Table 12-III. The gas-productive portion of the reservoir is predicted by the normal water saturation figures and zero to trace of oil down to sample 5. At this point the oil saturations make a decided upward increase with little change in

TABLE 12-III

Gas-Oil and Oil-Water Contacts

(J sand, Nebraska)

Sample No.	*Porosity*	*Permeability*	*Residual Oil Saturation*	*Water Saturation*	*Probable Type of Production*
1	20.4	55	0	36.0	Gas
2	21.1	56	0	31.6	Gas
3	23.8	731	Trace	33.8	Gas
4	23.2	422	Trace	31.0	Gas
5	25.5	248	13.3	38.4	Oil
6	23.7	226	16.4	37.0	Oil
14	23.4	219	17.9	37.9	Oil
15	24.5	263	12.5	38.3	Oil
16	22.8	213	6.3	45.6	Water
17	23.1	225	5.1	46.8	Water
18	21.4	146	1.7	55.5	Water
19	19.3	112	0	85.0	Water

water, and the gas-oil contact is interpreted as lying between the depths represented by samples 4 and 5. Sample 16 shows a decrease in oil saturation, with an increase in water; and the transition zone, or water table, is predicted at the depths represented by samples 15 and 16, with water definitely and unquestionably present 3 feet lower.

Preliminary data are usually available to the operator before the well is ready for perforation, and these data will enable the operator to perforate below the gas-oil contact (if present) and above the oil-water contact. The permeability profile from the preliminary report also assists the operator in placing the shots to avoid highly permeable streaks that might permit entrance of water to the bore hole and tight, unsaturated rock that would not add to production.

Reservoir Information

The saturations so useful in well-completion information are seldom used in a reservoir study. The reservoir engineer is primarily interested in the storage capacity of the rock, the permeability distribution in the reservoir, and the percentage of water under reservoir conditions. Porosity and permeability are reported in the routine analysis, but connate water must be estimated or determined in some other manner.

The same plugs on which porosity and permeability measurements were made can be used for connate-water study provided that the routine core-analysis methods were of the type that do not contaminate or destroy the specimen. The thoroughly cleaned and dried plugs are saturated with formation water or a brine equivalent and subjected to a displacing fluid, either oil or air, which displaces part of the water. Pressure differential is obtained by placing one face of the saturated specimen in contact with a water-permeable plate or membrane and applying pressure to the displacing fluid. Connate water saturation is reached when a large increase in displacement pressure results in a negligible decrease in water saturation.

The Messer evaporation technique (Messer, 1950; Dodd, 1951) is just as reliable and much faster than the plate method above described. The cleaned and dried specimen is saturated with a volatile solvent (usually toluene), weighed, and suspended from a recording balance similar to the Gramatic. A slow current of dry, warm air is passed across the specimen, and the weight is recorded at equal time intervals. Connate water saturation is assumed to be reached when the rate of evaporation, measured by the loss in weight, becomes constant.

The use of oil or oil-base mud as a coring medium gives a reliable measurement of connate water. Connate water, being that fluid left coating the inner surface area of the pore space not displaced by the invading oil, is assumed to be immobile and will not be displaced by filtrate invasion or fluid expansion;

thus, a filtrate other than water will not change the connate-water saturation of the core. Oil or oil-base mud will displace interstitial water to the extent that a transition zone or the actual water table might appear oil productive when interpreted on the basis of laboratory results. For this reason, the use of such coring fluids is not advisable when the oil-water contact is in question.

The basic data necessary for reservoir information are contained in the routine measurements of porosity and permeability, and the special measurement of connate water. Of further value to the reservoir engineer are studies such as relative permeability, water-flooding tests, displacement tests, pore-space distribution, and many others.

CORE-ANALYSIS REPORTING

Core-analysis results (fig. 12-4) are reported in a variety of forms of tabular and graphic arrangement. First and foremost are the tabular results of the analysis on an individual footage basis which can be expanded to include drill-stem-test data, lithology, perforated zones, and any other information the individual operator deems most essential. The same material is often graphically portrayed in such a manner that producible zones can be selected at a glance. Color adds to the picture, and attention to detail and color selection often results in a very artistic and easily interpreted graph.

The next step is to group the tabular results into producible sections or zones with a weighted summary for each. This can be expanded, if connate-water and formation-volume factor data are known, to include stock-tank oil in place and estimates of recoverable oil under the different types of drive that might be present in the reservoir.

The movement of oil or gas from the reservoir into the well bore is a function of permeability, among other factors. It is believed that the oil moves first from and through the more permeable channels; thus the flush or initial production will depend upon the total footage of higher permeability, irrespective of where or at what particular depths this footage occurs. Sections of lower permeability will progressively produce as the oil is exhausted in the higher permeability zones. One can assume, then, percentages of depletion in the permeability zones, a greater percentage of the oil in place being produced from the higher permeability zones down to only a small percentage of the oil in place in the extremely tight sections.

It is thus advantageous to segregate the net pay thickness into ranges of permeability, regardless of position in the lithologic column. These ranges can be empirically selected for a particular field or area, depending upon fluid characteristics; for example, a cutoff permeability of 5 millidarcys is used, and the selected ranges are: below 5 md, 5-25 md, 25-100 md, 100-500 md, 500 md and

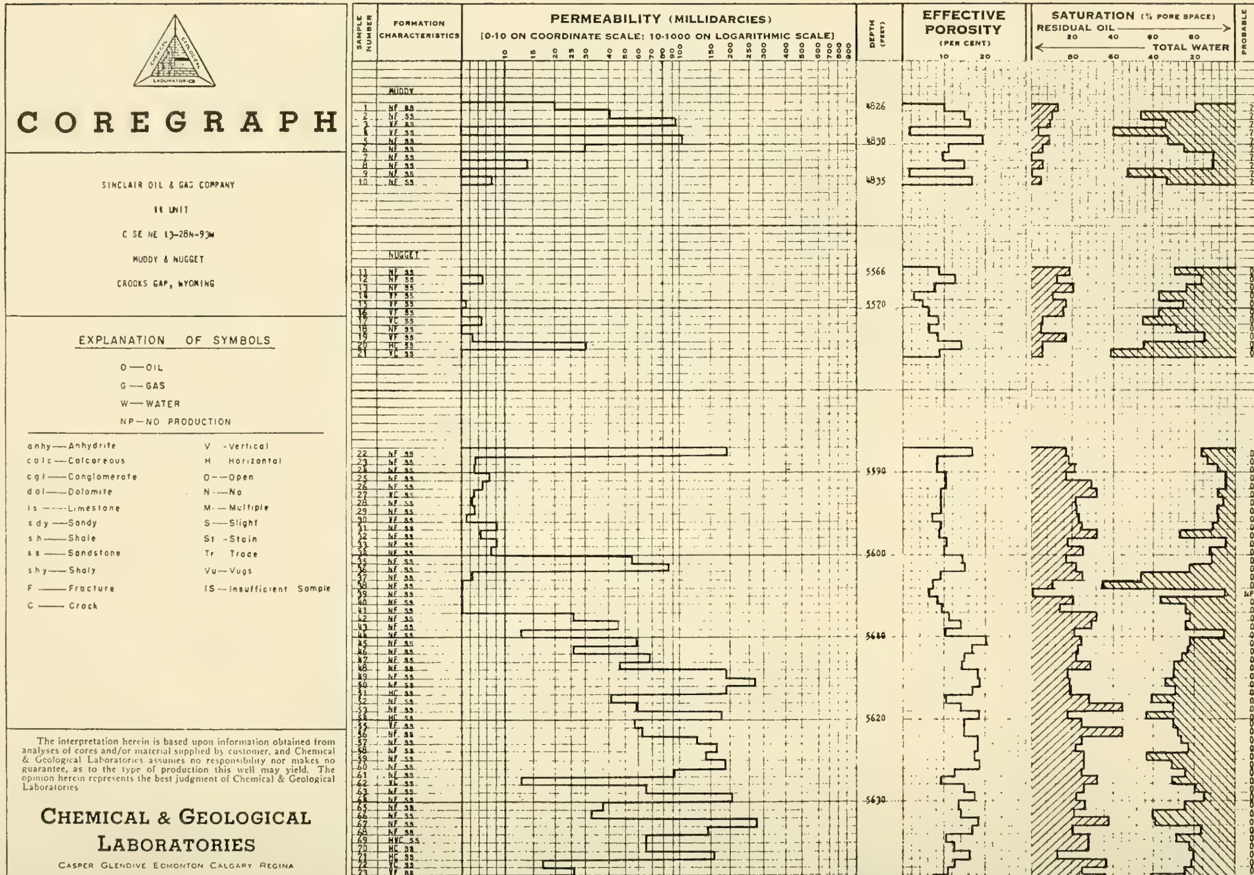

FIGURE 12-4. Coregraph presenting routine porosity, permeability, and fluid-saturation data (Courtesy Sinclair Oil and Gas Company).

above. Weighted average porosity, permeability, and saturations are calculated for each group.

Permeability distribution may be expressed in tabular form, or in a number of ways graphically. Block diagrams are often used, and it is not uncommon to plot the permeability of each sample in a consecutive series from the lowest to the highest reading. The presentation of the tabular data can be handled in any number of ways and can be varied to emphasize the features considered most important by the individual operator.

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Chapter 13

WATER ANALYSIS

J. F. Sage

The analyses of representative formation water samples from drill-stem tests on exploration, or from field development wells, can prove very valuable to geologists.

SAMPLING

Nonrepresentative samples of formation waters can lead to unnecessary analytical work and erroneous correlations. For these reasons it is important that uncontaminated formation water samples be collected whenever possible, and that contamination be detected when it takes place. The best way to accomplish this is to use what is known as the Chloride Ion Titration Method. In this method, the first sample for titration is taken of the filtrate from the mud stream just prior to the drill-stem test. Additional samples are taken from the drill pipe as it is being removed from the well. The number of samples that should be taken depends on the depth of the formation being tested (fig. 13-1). At least three samples should always be taken near the bottom: one approximately 100 feet above the tool, one approximately 50 feet above the tool, and the last as close to the tool as possible. All samples are titrated for their chloride-ion content, and the results are plotted in milligrams per liter against the corresponding depth of interval of drill pipe (fig. 13-1).

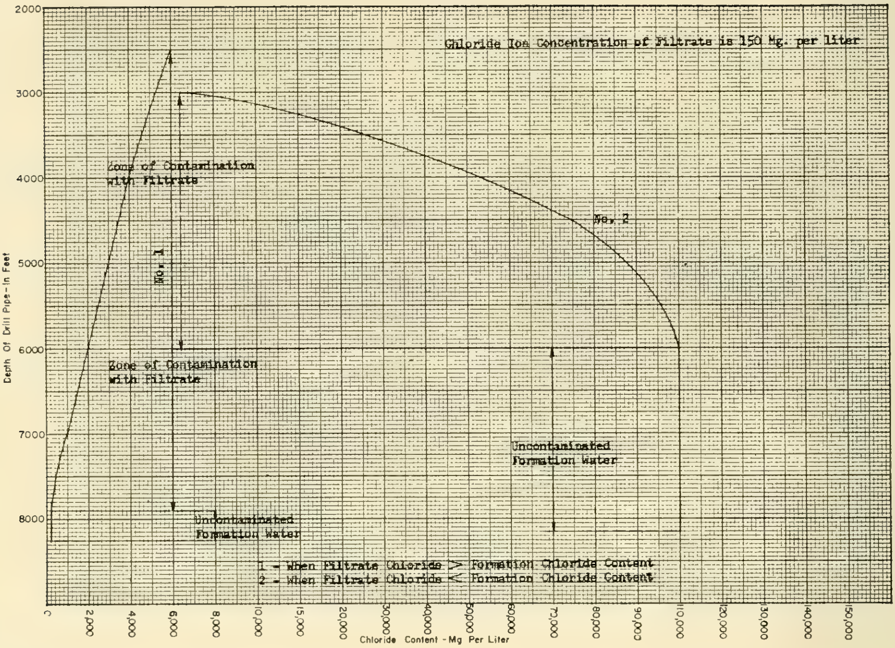


FIGURE 13-1. Variation with depth in chloride content of water during drill-stem test.

There is usually evidence, in such a plot, of a transition zone in which the chloride-ion content increases or decreases, and below which it reaches a constant value. The transition zone is interpreted as reflecting contamination and the zone of constant salinity as reflecting uncontaminated formation water. In many instances, the chloride content may reach a constant value, then increase or decrease in an erratic manner. These erratic values can be interpreted as indicating that the packer did not hold or, if the test is being made after a squeeze job, that the squeeze job was unsuccessful. If the squeeze job were unsuccessful, it, as well as the drill-stem test, would have to be repeated. With the information available from the titration test, the geologist or petroleum engineer could determine accurately whether the fluid recovered just above the tool was all drilling fluid, a mixture of drilling fluid and formation water, or all formation water. If the sample taken above the tool is found to be uncontaminated formation water, then at least a ½-gallon sample of the water should be sent to the laboratory for analysis, accompanied by a copy of the chloride-ion content plot. The laboratory analysis of this water can be used safely for future correlation work.

METHOD OF ANALYSIS In 1911, Palmer, then with the U.S. Geological Survey, invented a method of analyzing natural waters so they might be used for geological interpretation. Palmer's system emphasizes the important differences between waters and their geological relationship. He grouped those radicals that are either geochemically similar or geologically associated. Palmer started by grouping the common bases sodium and

SINCLAIR RESEARCH LABORATORIES, INC.
TULSA, OKLAHOMA

SRL-5005-5M-8-56

SAMPLE NO. S-3306 ANALYST JLB FORMATION Ellenburger DEPTH 13,153-13,178'

DESCRIPTION SOG G. R. Davis No. 1, Sec. 20, Twp. 5, Blk. 41, T & P R.R. Co. Survey

COUNTY Upton STATE Texas TAKEN 4-24-51 REC'D 4-30-51 ANALYZED 5-1-51

CONSTITUENTS IN PARTS PER MILLION			MEQ. PER LITER	REACTING VALUES IN PERCENT
POTASSIUM (K)	Trace	ALKALIES POTASSIUM		Trace
SODIUM (Na)	56105	SODIUM	2439.43747	39.84
LITHIUM (Li)	Trace	LITHIUM		Trace
CALCIUM (Ca)	10240	ALK. EARTHS CALCIUM	510.97600	8.34
MAGNESIUM (Mg)	1312	MAGNESIUM	107.89888	1.76
BARIUM (Ba)		BARIUM		
STRONTIUM (Sr)	170	STRONTIUM	3.87940	0.06
MANGANESE (Mn)	Trace	MANGANESE		Trace
CARBONATE (CO_3)		WEAK ACIDS CARBONATE		
BICARBONATE (HCO_3)	151	BICARBONATE	2.47489	0.04
HYDROXIDE (OH)		HYDROXIDE		
SULPHATE (SO_4)	483	STRONG ACIDS SULPHATE	10.05606	0.17
CHLORIDE (Cl)	108144	CHLORIDE	3049.66080	49.79
TOTAL SOLIDS		SPECIFIC GRAVITY AT 15.6°C 1.119	pH 6.81 @ 26°C	

PROPERTIES OF REACTION IN PERCENT					
PRIMARY SALINITY 79.68	PRIMARY ALKALINITY —	CHLORIDE SALINITY 99.66	RES 0.049	O.M. 75°	°F
SECONDARY SALINITY 20.24	SECONDARY ALKALINITY 0.08	SULPHATE SALINITY 0.34	NaCl EQ. 176882		P.P.M.

REMARKS

PATTERN WATER ANALYSIS SYSTEM

SCALE: MEQ. PER LITER

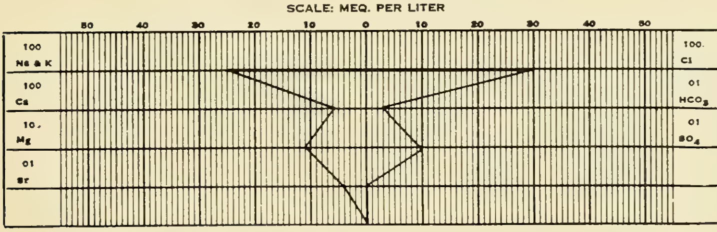


FIGURE 13-2. Recording of water-analysis data.

potassium as alkalies (fig. 13-2); calcium and magnesium as alkaline earths; carbonate, bicarbonates, and sulphides as weak acids; and chloride, sulphates, and nitrates as strong acids.

Palmer calculated the reacting values in percent of the radicals. Using the four groups, he separated natural waters into four classes, according to the reacting values of the radicals. The four classes are primary and secondary salinity, primary and secondary alkalinity. Alkalies in connection with strong acids cause primary salinity. If the strong acids are greater than the alkalies, excess of the strong acids with an equal value of alkaline earths induces secondary salinity. Primary alkalinity is excess of alkalies over strong acids, with equal value of the weak acids. Secondary alkalinity is excess of the weak acids combined with an equal value of alkaline earths. Secondary salinity and primary alkalinity are incompatible. Each natural water will have two or three of these properties of reaction, but never all four. In addition, the percentage of chloride and sulphate salinities are computed and may be used as criteria for comparison.

Most formation waters contain some of the heavier minerals, generally in minute quantities, as well as some dissolved gases. In the past, these minerals and gases were not analyzed. Today, however, with the special instruments that have been developed, such as flame spectrophotometer and gas chromatography instruments, any element or gas present in the water can be determined quantitatively. For gas analysis, a special sampling tool is required so that the sample can be taken and delivered for analysis under bottom-hole conditions. These more complete analyses have given us a better understanding of the geochemistry of formation waters and their application to the waters of petroleum accumulations.

WATER PATTERNS

Water patterns for correlating waters have been used for many years. Today, a system developed by Stiff (1950) makes it much easier for geologists to compose a file of analyses and patterns containing information on all formation waters. This preferred system of graphically presenting water analyses uses the reaction values expressed in milli-equivalents per liter directly, rather than on a percentage basis. Thus, the actual concentration of the ions is employed; and two unlike waters, differing only in concentration, can be distinguished from each other. The more important constituents are plotted on horizontal lines extending left and right from a vertical line at zero. Positive radicals are plotted to the left, and the negative radicals to the right. The figure above each radical gives the scale upon which the radical is plotted. Figure 13-3 shows how the pattern system can be used to correlate and classify waters (Sage, 1955).

We shall assume that a well was drilled to formation B and squeezed off formation A, which lies a few hundred feet above formation B. A drill-stem

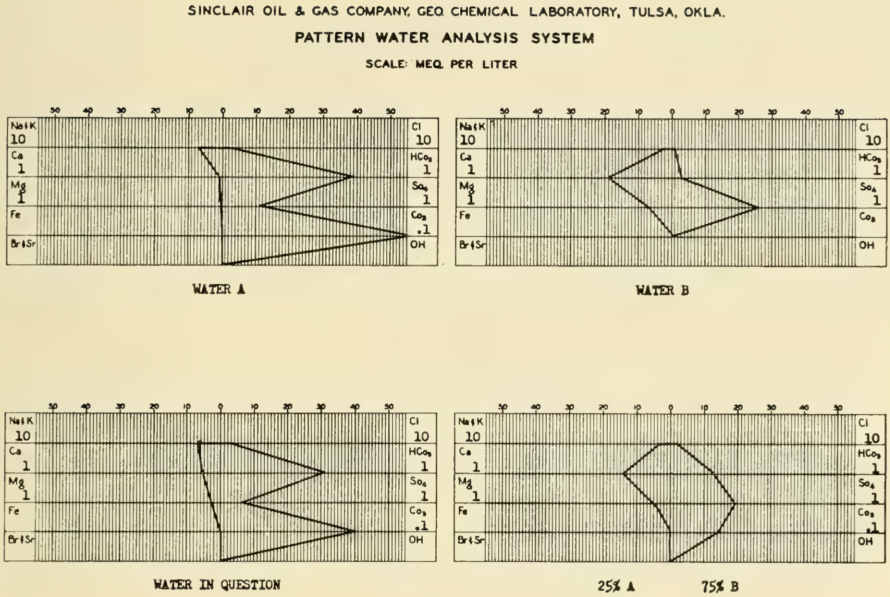


FIGURE 13-3. Water-analysis patterns.

test of formation B encountered water from which a sample was taken and sent to the laboratory for analysis. The pattern of this water plotted in Figure 13-3 is marked "water in question". Patterns for formations A and B waters are marked water A and B. They have been plotted from samples known to be representative of formations A and B. On observing these patterns, one notes that the pattern of the water in question does not match with A or B, and therefore, probably is a mixture of the two. Now various mixtures of waters A and B are calculated, and their patterns are plotted (figs. 13-3 and 13-4). If it is assumed that a mixture of 25 percent water A and 75 percent water B is present, pattern No. 4 in Figure 13-3 would be obtained. A mixture of 50 percent water A and 50 percent water B gives pattern No. 1 (fig. 13-4). A mixture of 75 percent water A and 25 percent water B gives pattern No. 2, Figure 13-4. Now, if these patterns are compared with the patterns in Figure 13-3, one may observe that the pattern 2 of Figure 13-4, which is composed of 75 percent water A and 25 percent water B, is the same as the pattern of the water in question (fig. 13-3). Therefore, the water in question is composed of 75 percent formation A water and 25 percent formation B water. With this information, the well could be resqueezed and the upper water shut off.

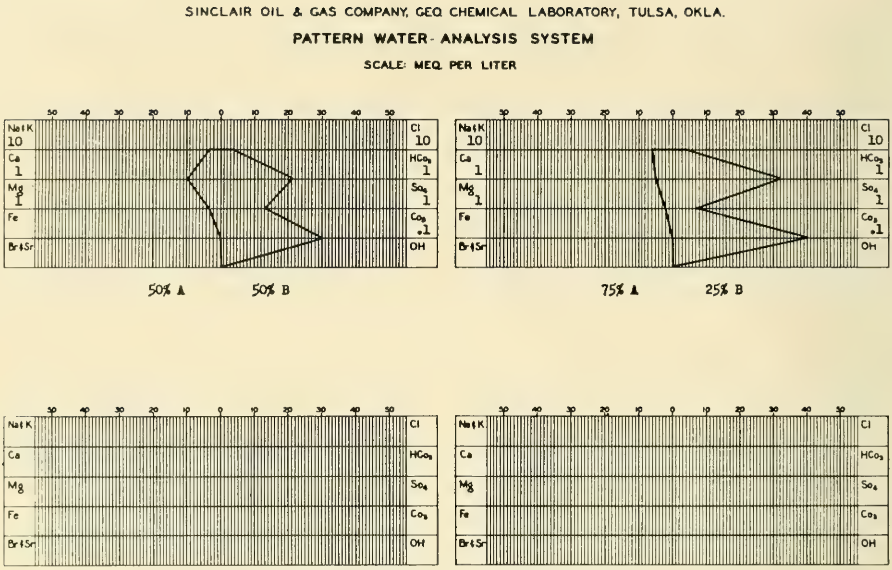


FIGURE 13-4. Water-analysis patterns.

ELECTRIC RESISTIVITIES OF OIL-FIELD BRINES

A knowledge of the resistivity of formation waters is essential for the fullest utilization of the electric log. The resistivity of formation waters may be measured directly with a resistivity meter or calculated from the mineral analyses, a procedure which eliminates the need of estimating formation-water resistivity and should result in increased accuracy of quantitative log interpretation. Water-resistivity data also are useful for determining casing leaks in wells and for identifying geological formations. The resistivity of waters varies with temperature and with both the quantity and type of salts in solution.

WATER RESISTIVITY

Resistivity of water is defined as the property of water that resists the flow of an electric current. The unit most generally used in electric-log interpretation is the ohm-meter (ohm), which expresses the resistance in ohms of one cubic meter of water to the flow of a uniform electric current parallel to one side of the cube. Water resistivities sometimes are expressed in ohm-meters squared per meter (ohm-m^2/m), or in ohm-centimeters (ohm-cm). Conversion factors that have been determined experimentally permit conversion of the various ionic concentrations, as determined by water analysis, to equivalent concentrations of sodium chloride. The sum of equivalent concentrations gives the equivalent sodium-

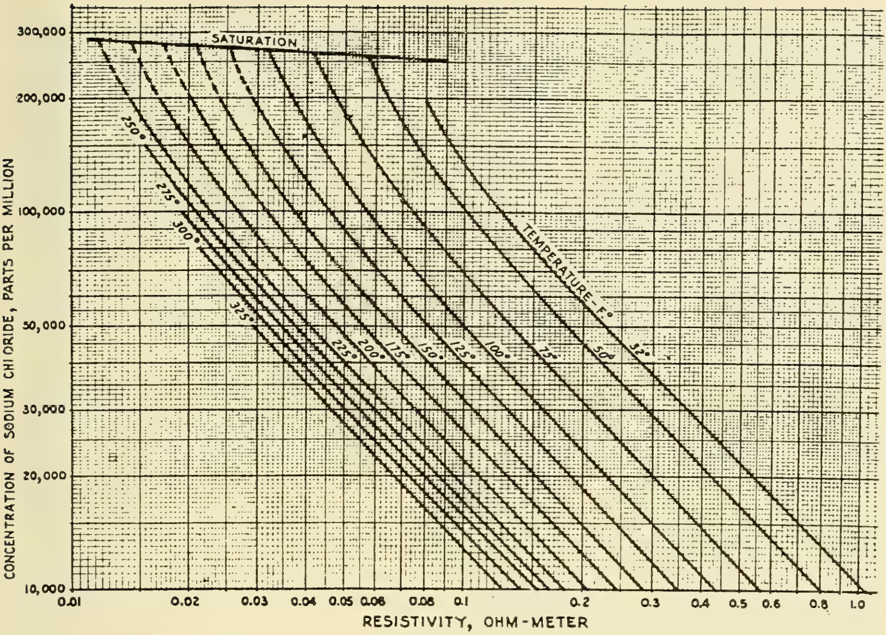


FIGURE 13-5. Resistivity — sodium chloride concentration curves.

chloride concentration of the water (Table 13-I). Using this concentration, one can obtain the resistivity of the water at the desired temperature directly from the curve in Figure 13-5. Close agreement can be obtained between the calculated and measured resistivity on the same water sample.

TABLE 13-I

Ionic Constituents	*Concentration p.p.m.*	*Conversion Factor*	*Equivalent Concentration of NaCl*
Sodium (Na)	56105	1.00	56105
Calcium (Ca)	10240	.95	9728
Magnesium (Mg)	1312	2.00	2624
Sulphate (SO_4)	483	.50	241
Chloride (Cl)	108144	1.00	108144
Carbonate (CO_3)	0	1.26	0
Bicarbonate (HCO_3)	151	.27	41
			176883

Calculated resistivity (fig. 13-5) at 75F = 0.049 ohm-meter
Measured resistivity (fig. 13-5) at 75F = 0.054 ohm-meter

IONS IN WATER

Sulphate (SO_4)

The sulphate ion constitutes one of the most important elements to be considered in connate water. It almost always has significance (Schoeller, 1955). The SO_4 ion is proof that rocks contain gypsum and that anhydrite is or has been in contact with connate water. A very small content of calcium sulphate in the rocks suffices to cause a high concentration of sulphate in water. The solution of calcium sulphate is rapid. Also, a stagnant or partly stagnant water, like that of connate water, having passed through certain land areas which even may be very poor in calcium sulphate, is itself capable of becoming highly saturated, even to the point of complete saturation in calcium sulphate.

It is the solubility of gypsum ($CaSO_4 + 2H_2O$), one of the least soluble sulphates, that governs the content of sulphate in water. The solubility of gypsum is 2.095 grams per liter in pure water, but this is increased with the concentration of NaCl up to 131 grams per liter of NaCl. The maximum solubility is then 7.3 grams per liter of $CaSO_4$, beyond which the solubility decreases; but at saturation the content of sulphate is variable, because it depends upon the calcium content in the water. Some calcium can be brought into the water by the exchange of bases. Similarly, this process is capable of reducing the content of sulphate. In some other instances, on the contrary, the exchange of bases will replace calcium by sodium. The possibility then arises of increasing the content of SO_4. The amount of sulphate in connate water is extremely variable. There is a tendency to saturation in $CaSO_4$, as there is a tendency to saturation in NaCl for the same reasons, and this saturation is rapidly attained because of the ease of the solution of $CaSO_4$, and of the degree of stagnation of the water.

The sulphate water in contact with petroleum accumulations can furnish the reducing conditions which transform sulphate to sulphur.

Although there is a tendency to saturation in $CaSO_4$, this saturation does not always exist. Much of the connate water is relatively low in SO_4, as much of it is low in NaCl. This condition exists in some of the pools of the Rocky Mountains, the Gulf Coast, and many others. The reason is probably due to the liberal circulation of meteoric waters, but the tendency to saturation is extremely frequent. It has been observed in the waters of thrust zones and the water from the slate beds of Boryslaw, the waters of the Carboniferous and Permian anticline of Polasna-Krasnokamsk in Russia, the waters of Pechelbrown (Schoeller, 1955), waters from the Permian Basin from Reagan County in West Texas (Berger and Fash, 1934), from Oklahoma (Case, 1934) and from Illinois.

In saturated or nearly saturated water, the SO_4 content is very often lower in number of milli-equivalents at the saturation point and frequently may be exceedingly low. This fact gives proof that the large quantity of calcium in the water has its origin above all in an exchange of bases (a small part only produced from solution of limestone). Then $Ca > SO_4$, with $(SO_4) \longrightarrow S$.

The amount of calcium by exchange of bases in water already saturated with SO_4 ought necessarily to cause a precipitation of $CaSO_4$ in the beds, decreasing therefore the content of SO_4 in the water and increasing that of calcium.

When the exchange of bases is non-existent, or very weak, or indeed, when it increases the calcium ions of the water against the sodium and magnesium ions, the SO_4 content in milli-equivalents can be the same or even higher at the point of saturation — hence the possibility of having $Ca < SO_4$. Theoretically, an exchange of negative bases, in bringing about a decrease of calcium in the water, can permit new solutions of SO_4 and bring about, in consequence, SO_4 above the point of saturation. But as these new solutions are from the $CaSO_4$, there is then little chance that SO_4 will be raised above the saturation point unless the SO_4 can show $MgSO_4$ in solution or some other SO_4.

It has been observed frequently that water rich in SO_4 has a bearing on the high Mg/Ca ratio. This fact should prove that water saturated with $CaSO_4$ can then dissolve some $MgSO_4$, which is very soluble, or some other magnesium salt. In the Permian sands from the Itan-East Howard pool, Howard County, Texas, and the North Cowden and Penwell pools in Ectoy County, Texas, this condition is present. One water from the Cowden pool had saturations of 3 grams per liter of calcium, 34 grams per liter of magnesium and 27 grams per liter of SO_4.

The tendency to saturation does not abolish the reduction of sulphates. Hence, the water from the Carboniferous and from the Permian anticline of Polasna-Krasnokamsk are very rich in H_2S—so very rich, that it is difficult to avoid the conclusion of the presence of a reduction of sulphates. It is simply the question of a phenomenon of dynamics of the relative speed of the circulation in solution of $CaSO_4$ from one part and of a reduction of sulphates of the other part. In the Polasna-Krasnokamsk water, the speed of solution surpasses the speed of reduction. When, on the contrary, the speed-of-reduction phenomenon is greater than the speed of solution, the reduction deviates very perceptibly and causes a very sharp decrease of SO_4, which can even disappear. The weak content of SO_4 or its absence have been observed for a long time in connate water and considered as one of its exact characteristics.

The reduction of sulphate in connate water brings, then, a considerable decrease, or even a disappearance, of the ion SO_4 and its replacement by the ions S, S_2O_3, and SO_3. Therefore, in some connate waters where SO_4 is only in very small quantity, or even absent, it is replaced by H_2S, S, S_2O_3, and SO_3.

A few observations on the existing relation between the geological structure, the petroleum pools, and the reduction of sulphates are available.

In the San Joaquin Valley of California (Rogers, 1917), it has been found that the surface waters and the normal underground waters, of meteoric origin, outside of the petroleum fields, are rich in sulphate; whereas, in the petroleum fields, the concentration in sulphate of the waters decreases in depth and is practically absent in the field waters. The sulphides and hydrogen sulphide appear near the level where the sulphate commences to decrease, and they exist among the numerous waters located above petroleum beds. The quantity of sulphides in the deep waters is obviously directly proportional to the quantity of sulphate in the water located just above.

In the anticline of Polasna-Krasnokamsk also, the hydrogen sulphide has no distribution. The concentration of H_2S is particularly high in the top beds and is strong in the suboil beds, but it is extremely weak in the edge waters.

In some deposits there is the almost total absence of sulphates and, at the same time, complete absence of H_2S. This fact indicates that the reduction of sulphates was made a long time ago, that it was made completely, and that it is now arrested. This fact implies, in consequence, the existence of a bed in which water and petroleum are found in an enclosed hydrostatic system (no movement of fluids).

In some other instances of absence of SO_4, H_2S is present. It is admitted that H_2S proceeds from an ancient reduction of sulphate and that it is stored in the deposit as other gases are stored. But it can just as well be thought that a reduction of sulphates is in progress, which, in consequence, necessitates a relatively weak introduction of foreign water in the water deposit, such that the phenomenon of reduction can be produced in a complete or almost complete manner. This, in particular, could be an explanation of the water deposits of Rumania and California.

In West Texas, waters saturated with calcium sulphate, contain large quantities of H_2S. The reduction of SO_4 to H_2S no doubt occurred in a foreign water that later penetrated the deposit.

Hydrogen sulphide can exist in large quantities due to its high solubility. The quantity of S, S_2O_3, and SO_3 ions is generally small. Where there is a reduction of SO_4, there is also an increase in the content of carbonic gas (CO_2) in the petroleum deposits, an increase in the content of CO_3 combined with water; and an increase of free CO_2. The reduction of SO_4 very often seems to cause a decrease of CO_3 content of the waters by the precipitation of $CaCO_3$.

Nitric and Nitrous Ions (NO_2, NO_3)

The nitric and nitrous ions (NO_2, NO_3) of connate water have been the object of very few determinations, except in Illinois.

A few measurements executed outside of Illinois give only the concentration of several milligrams, rarely of ten milligrams. It is evident that the pressure of a reducing agent does not favor the formation or the maintenance of the nitrates and also, to a lesser degree, of the nitrites; whereas it permits the formation and the maintenance of NH_4, which can attain extremely high values.

Phosphates (PO_4)

The lime phosphates also are much less soluble than the alkaline phosphates. Calcium also regulates the concentration in the phosphoric ion of the water. In the connate waters, the concentration in phosphate is not especially high. More often it is absent or does not exceed about 10 milligrams of PO_4. Where high values are found, the waters generally contain high concentrations of sodium. Perhaps the high concentrations in CO_2 of petroleum water are also contributing causes. There does not seem to be a direct relationship between these very high concentrations and the presence of petroleum.

In the underground waters charged with CO_2 and humic acids, such as peat bogs, phosphorus is found frequently in very high concentrations.

Acids and Carbonic Gas (HCO_3, CO_3, CO_2)

The connate waters are characterized by a high concentration in free carbonic gas which reflects in a strong concentration in HCO_3 ions. The greater part of the gases of petroleum beds have higher concentrations of CO_2 than the atmosphere or the atmosphere above the underground waters.

Sodium (Na)

Sodium is extremely variable in formation waters, as it has different origins. It can come either from soluble sodium salts, enclosed in the sedimentary rocks, Na_2CO_3, Na_2SO_4, NaCl, but more particularly NaCl (because the first are more rare), or from the decomposition of the silicates, particularly the feldspars. The latter decomposition is difficult, much more difficult than the taking in solution of the free sodium salts in the rocks. Another source of sodium is in the exchange of bases. The solution of soluble salts brings chlorine into the water, little SO_4, little CO_3, because of all the soluble sodium salts in the rocks, NaCl is most abundant.

Potassium (K)

The potassium content in connate waters varies considerably, but sometimes it is much less than that of sodium. It is generally missing in the waters of weak concentrations. The ratio K/Na is a function of the concentration in sodium (Schoeller, 1955).

Ammonia (NH_4)

Ammonia can come directly from sea water, nitrates, nitrites, and organic material. Ammonia may come from petroleum after its formation.

Lithium (Li)

Lithium, like NO_2 and NO_3, has been rarely determined; however, some connate waters have been found to contain abnormally high concentrations of this element.

Magnesium (Mg)

Magnesium, like calcium, has some decidedly variable values, but they far from attain those of calcium. Some magnesium salts have a greater solubility than those of calcium. Only in very few waters has the concentration of magnesium been found to exceed that of calcium. One water of the Permian Basin of West Texas, contained 3 grams per liter of calcium and 34 grams per liter of magnesium. Calcium and magnesium are not found in some waters, which are generally waters of weak concentration and meteoric waters that have penetrated the beds and, in doing so, have undergone a reduction of SO_4 or an exchange of bases.

Calcium (Ca)

The calcium content of connate waters is variable. The calcium has its origin essentially by dissolution of certain sedimentary rocks, particuarly of limestone, dolomite, gypsum, anhydrite, and marlstone. Sandstones contribute only through their cementing material; and the crystalline rocks contribute only small quantities. The calcium content can be increased by the exchange of bases, or it can be decreased by the reduction of SO_4 or by the exchange of bases of calcium against sodium at which point the content of calcium can fall to zero.

Strontium (Sr)

Some connate waters contain high concentrations of strontium, but, conversely, some do not contain any, or very little. Because strontium is a companion of calcium, limestones may be rich in strontium. Waters with the highest calcium content, as a rule, are the richest in strontium. However, it is the SO_4 ion and the free CO_2 in the water that determines the amount of the element that can remain in solution.

Barium (Ba)

It is the extremely weak solubility of barium that regulates the content of barium in connate waters. But the concentration can be considerably increased by the chlorine and sodium content of the water, and by a weak concentration or absence of the SO_4 ion.

Manganese (Mn)

Very few determinations of manganese have been made on connate waters. In waters where it has been determined it was found to be present in very minute quantities.

Boron (B)

Some concentrations of boron found in the ordinary vadose waters of the sedimentary formations are high compared to the very small concentrations generally found in the waters from crystalline rocks. Boron occurs in the boric acid or borate state.

Nickel, Cobalt, Arsenic (Ni, Co, As)

It is known that these metals exist in petroleum, but only recently their presence in connate waters has been determined.

SUMMARY COMMENTS

Water analyses have proved very valuable not only in subsurface studies with respect to underground water migration, but also in electric-log interpretation and in well remedial and recompletion operations.

The value and application of water analyses are greatly improved if care is exercised in taking the samples and some method of graphically presenting the individual water information is used. A graphical presentation can indicate clearly that waters from various formations, even though very similar, can be distinguished easily from each other. Changing scales on the diagrams to accentuate a certain component may be the key to identification; however, scale changes must be done with caution to avoid confusion when comparing or correlating.

For the pattern system to be effective, a laboratory analysis of at least six chemical components is necessary. If the analyses are to be used for subsurface studies, as complete an analysis as possible should be made because the presence or concentration of each component has significance.

Part Three

WELL-LOGGING METHODS AND INTERPRETATION

Chapter 14 ELECTRIC LOGGING

Maurice P. Tixier

Electric logging is one of the important branches of well logging. Essentially, it consists in recording the resistivities of the subsurface formations and the spontaneous potentials generated in the boreholes. Electric logging was presented to the oil industry more than 20 years ago and has been accepted as one of the most efficient tools in the search for and the production of oil and gas.

FUNDAMENTALS OF ELECTRIC LOGGING

With electric logging, the corresponding parameters are measured *in situ* by means of appropriate bottom-hole instruments and are recorded continuously at the surface. The measurements are performed only in the uncased portions of the boreholes.

It has become general practice, when a hole has been drilled or at intervals during the drilling, to run an electrical survey for the purpose of quickly securing a complete record of the formations penetrated. This recording is of immediate value for the geological correlation of the strata and also for the detection and evaluation of possible productive horizons.

In addition to the spontaneous potential curve, several different kinds of resistivity curves or logs now can be recorded in the boreholes. These logs are obtained by the use of different resistivity measuring devices and are designated as conventional logs (normal and lateral), Laterolog, Induction log, MicroLog, etc.

An example of a conventional electric log is given in Figure 14-1.

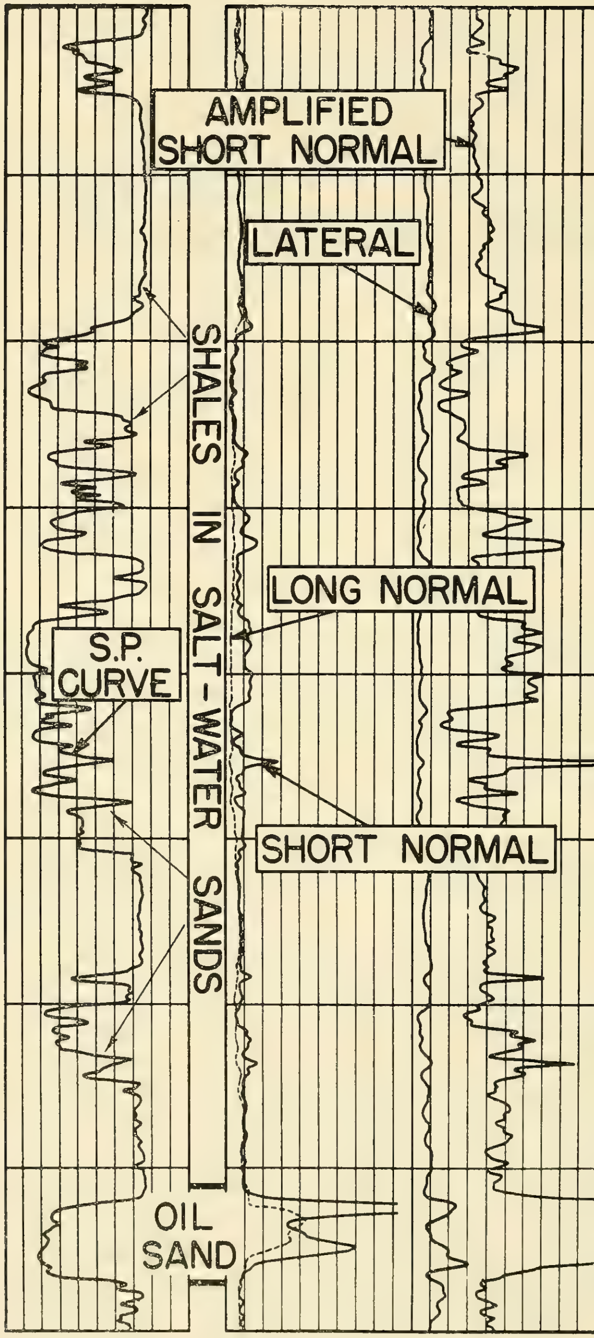


FIGURE 14-1. Conventional log profiles.

Formation Resistivities

The resistivities of the formations are important clues to their probable lithology and fluid content. Formations conduct electric current only by means of the mineralized water that they contain. The minerals that constitute the solid parts of the strata are insulators when absolutely dry. The few exceptions are metallic sulphides, graphite, etc., which conduct electricity like metals. In a similar manner, any pure oil or gas in the formations is electrically nonconductive. Other important factors in formation resistivity are the shape and the interconnection of the pore spaces occupied by the water. These depend on the lithology of the formation and, in reservoir rocks, on the presence of nonconductive oil and gas.

Unit of Resistivity

In electric logging, the resistivity is measured. The exception is induction logging, which simultaneously records a conductivity curve and its reciprocal, the resistivity. The unit of resistivity is the ohmmeter. When a uniform electric current is sent through a 1-meter cube in a direction parallel to any edge, the resistance in ohms is equal to the resistivity of the substance.

Relation of Formation Resistivity to Interstitial Water Salinity and Temperature

The resistivity of a formation depends directly upon the resistivity of the water in its pores. The dependence is a linear function.

In electric logging, the resistivity of a formation water quite often has to be deduced from a knowledge of its salt content. The following laws of electrolytic conductance should be borne in mind.

A. *The conductivity of an electrolyte increases in proportion to the amount of chemicals in solution; thus, the resistivity decreases with increasing salinity* (fig. 14-2).

B. *The resistivity of an electrolyte decreases as its temperature increases.*

Relation of Formation Resistivity to Lithology

The ability of a formation to conduct current is directly affected by the amount of water in the pores: i.e., by the porosity of the formation.

Many experiments made on various porous formations have shown that in permeable formations that do not contain shaly material the formation resistivity can be related solely to the porosity through a comparatively simple empirical formula.

In order to express this relation, it is convenient to make use of a parameter called formation-resistivity factor, which is equal to the ratio R_o/R_w. R_o is the resistivity of a given formation entirely filled with water, and R_w is the resistivity of the water in its pores. For all formations that do not contain shaly material, the formation factor is a constant, whatever the resistivity of the water.

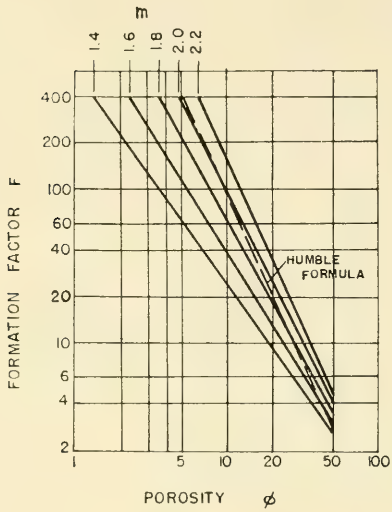


FIGURE 14-3. Porosity — formation factor graph.

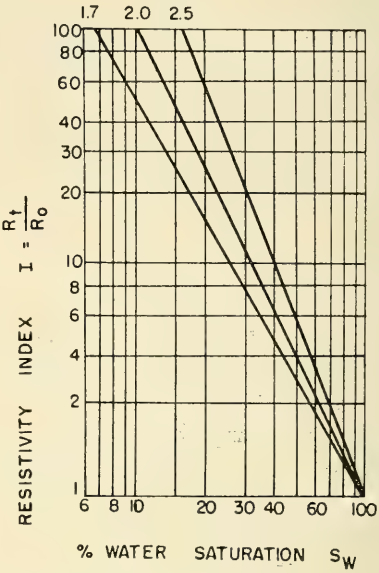


FIGURE 14-4. Water Saturation — resistivity index graph.

It has been found experimentally that the formation factor can be expressed with reasonable accuracy in terms of porosity by the equation

$$F = a/\phi^m \qquad (1)$$

F = formation factor

ϕ = porosity

m = an exponent called cementation factor, which varies with the lithology

a = coefficient

Several values have been proposed for a and m, but the resulting curves showing F versus ϕ do not differ much.

In the construction of numerous graphs for log interpretation, the formula proposed by W. O. Winsauer and others (1952) has been used:

$$F = 0.62/\phi^{2.15} \text{ (fig. 14-3)} \qquad (2)$$

Limestones often contain fissures and vugs caused by tectonic stress and leaching circulating waters. It is often advisable for these limestones to use relationships determined by local observations instead of the above formula.

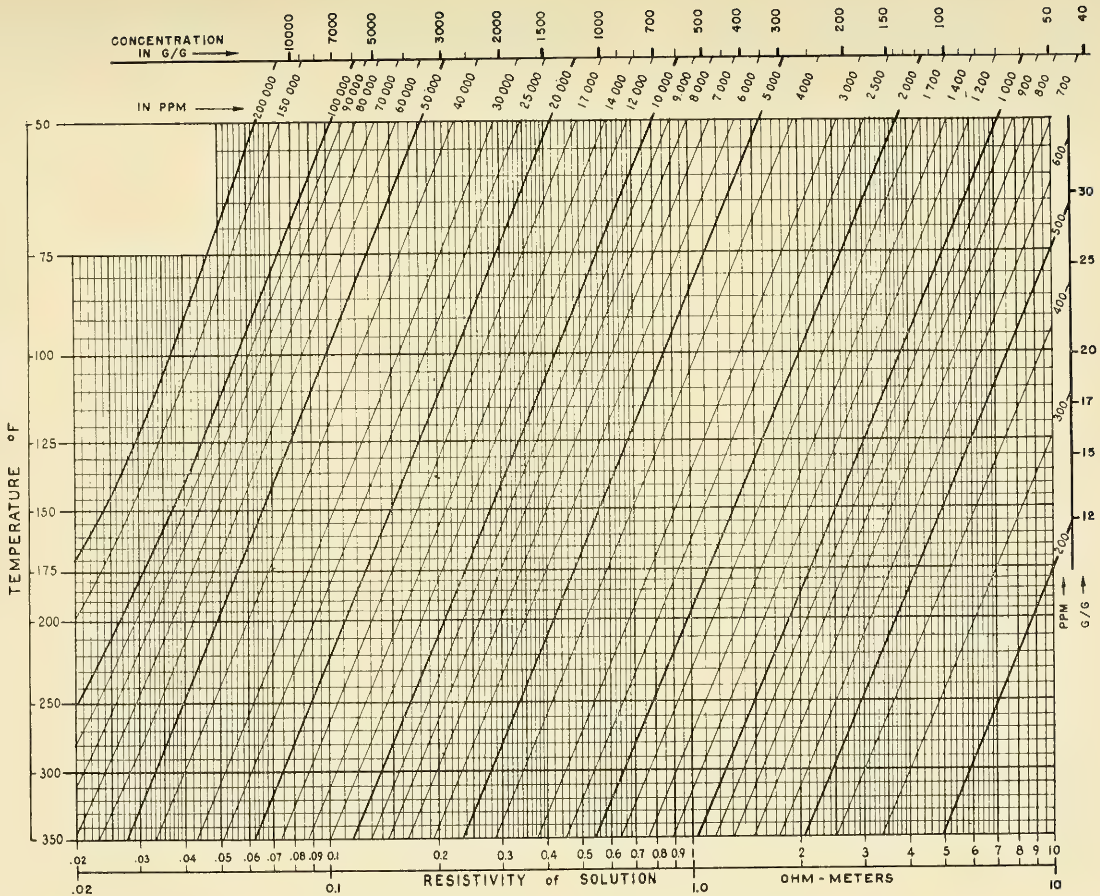


FIGURE 14-2. Resistivity graph for salinity and temperature.

Shales and clays are porous and usually impregnated with mineralized water. They have, therefore, an appreciable conductivity. On the other hand, the size of the pores is so small that practically no movement of fluid is possible. Accordingly, the shales, whether deposited in thin laminations or dispersed in the interstices of the sand grains, contribute to the conductivity of the formation, without contributing to its effective porosity. The relation between formation resistivity and porosity becomes more complex than that for clean formations.

The argillaceous materials present within permeable formations such as sands, are often designated under the descriptive expression of conductive solids.

Because of the additional conductance due to the presence of interstitial shale, the ratio of formation resistivity to water resistivity (i.e., the formation factor) changes when the resistivity of the water changes. Nevertheless, if the shale content is not too great, it has been observed experimentally that this ratio is almost constant for low values of water resistivities. Accordingly, the formation factor measured when the pores contain highly mineralized water can be considered, at least to a first approximation, as a characteristic parameter of the formation that is related to the effective porosity through equation 2, as in clean sands.

Evaluation of Formation Resistivity to Fluid Saturation

When a part of the pore space is occupied by an insulating material such as hydrocarbon, the resistivity of the rock increases with respect to the value it would have if it were 100 percent water bearing. The resistivity of such rock is a function of the relative proportion of hydrocarbons and connate water in the pores. The parameter generally used in well-logging interpretation is the water saturation, S_w, i.e., the fraction of pore volume occupied by water.

The water saturation in a reservoir rock in turn depends on many factors:

A. *Characteristics of the rock (porosity, permeability, surface areas of grains, etc.).*

B. *Characteristics of the fluids present (viscosity, density, etc.).*

C. *Height above the water table of the level under study.*

For substantially clean formations, the relation between formation resistivity and fluid saturation can be expressed by the following equation:

$$S_w = (R_o/R_t)^{1/n} \qquad \text{(fig. 14-4)} \qquad (3)$$

S_w = water saturation (proportion of pore space occupied by water)

R_t = resistivity of the formation (containing hydrocarbons and water, with water saturation, S_w)

R_o = resistivity of the same formation when entirely saturated with the same water ($S_w = 1$)

The ratio R_t/R_o is sometimes designated as the resistivity index I (accordingly, $S_w = I^{-1/n}$).

Furthermore, by definition $F = R_o/R_w$.

F = formation factor

R_w = water resistivity

Hence, equation 3 can also be written:

$$S_w = (R_o/R_t)^{1/n} = \left(\frac{F \times R_w}{R_t}\right)^{1/n} \tag{4}$$

The exponent n varies approximately between 1.7 and 2.2, depending on the type of formation. Experience shows that taking $n = 2$ should give a sufficiently good approximation in most instances for all practical purposes.

Equation 4 would, therefore, read:

$$S_w = (R_o/R_t)^{1/2} = \left(\frac{F \times R_w}{R_t}\right)^{1/2} \tag{5}$$

Again, the relation between formation resistivity and water saturation is more complex in shaly sands because of the additional conductance due to the shale network.

Schematic Representation of a Permeable Bed Invaded by Mud Filtrate

Usually, the hydrostatic pressure of the mud is greater than the natural pressure of the formations. Under these conditions, the mud filtrate tends to filter into the permeable beds.

Figure 14-5A represents a schematic cross section of a permeable bed penetrated by the borehole. For the sake of simplicity, the formation is supposed to be homogeneous, isotropic, and free of shaly material.

The diagram of radial distribution of resistivities is shown on Figure 14-5B, where the distances from the axis of the hole are in abscissae and the resistivities are in ordinates.

Starting from the axis, one encounters the following media:

Drilling Mud: Resistivity R_m

Mud Cake: Resistivity R_{mc}

The thickness and the nature of the mud cake depend on the nature of the mud and on the drilling conditions rather than on the formations. The thickness usually varies between ⅛ and 1 inch. In water-base mud, the resistivity of the mud cake (R_{mc}) is about equal to one or two times the resistivity of the

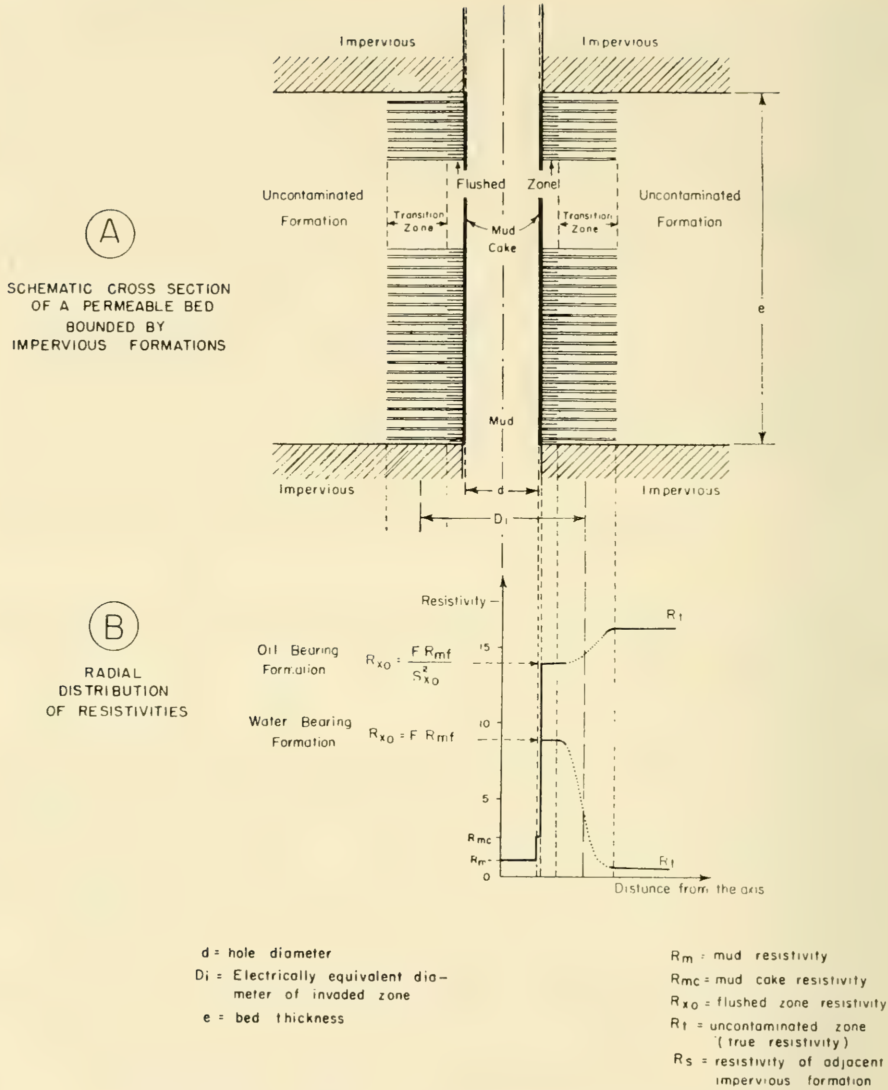


FIGURE 14-5. Schematic diagrams involving mud filtration.

mud (R_m). The difference may be appreciably greater in some oil-emulsion muds.

Flushed Zone: Resistivity R_{xo}

Behind and close to the wall of the hole, it is believed that the interstitial water which originally existed in the pores has been flushed entirely by the mud filtrate. This region, which generally extends over a distance of about 3 inches from the wall, is called the flushed zone of resistivity R_{xo}.

If the bed is water bearing, the pores in the flushed zone are completely filled with the mud filtrate. If the formation is substantially clean, the resistivity (R_{xo}) is equal to F x R_{mf}, F being the formation factor and R_{mf} the resistivity of the mud filtrate.

If the bed is oil bearing, the flushed zone contains a certain amount of residual oil. In this instance, R_{xo} is related to the resistivity of the filtrate (R_{mf}), the formation factor (F), and the water saturation (S_{xo}) in the invaded zone, as shown by the following equation derived from equation 5:

$$S_{xo} = \left(\frac{F \times R_{mf}}{R_{xo}} \right)^{1/2} \qquad (6)$$

$S_{xo} = 1 -$ ROS. (ROS = residual oil saturation)

Transition Zone

Behind the flushed zone, the distribution of fluids in the invaded zone varies continuously until a distance is reached where the formation has not been disturbed. This variable region is called the transition zone. We do not know clearly the distribution of the fluids in this zone. Accordingly, there is no real definition of the depth of the invaded zone; but it is convenient to introduce a factor, D_i, called the electrically equivalent diameter of invasion. The factor D_i is equal to the diameter of a fictitious homogenous invaded zone of resistivity, R_{xo}, which would have the same effect on the measurements as the actual invaded zone. This diameter, D_i, roughly corresponds to the diameter of a cylinder located midway in the transition zone.

It is also convenient in interpretation practice to consider the average resistivity of the invaded zone, R_i, which includes the flushed zone and the transition zone. The average water saturation in the invaded zone is called S_i and the average resistivity of its water R_z, such that:

$$S_i = \left(\frac{F \times R_z}{R_i} \right)^{1/2} \qquad (7)$$

As a general rule, all other conditions being the same, the greater the porosity and permeability, the smaller is the depth of invasion. If D_i is expressed in terms of *d*, the hole diameter, it can be said that with usual muds D_i seldom exceeds 2*d* in high-porosity sands but will attain 5*d* or more in low-porosity formations.

It has also been observed that in water-bearing sands with large vertical permeability, the depth of invasion is extremely small, often less than 3 inches.

This circumstance (which is very frequent in the Gulf Coast, for example) seems to be due to the difference in specific gravities between the mud filtrate and the connate water which permits the segregation of the two fluids. This is more likely to take place in a gas-bearing formation.

The invasion may also be extremely shallow and even negligible in low water-loss mud or oil-base mud.

Uncontaminated Zone

The resistivity of the uncontaminated zone of the formation beyond the invaded zone is called the true resistivity, R_t. The measuring devices do not always give the value of the true resistivity directly. Other media, such as mud column, invaded zone, and adjacent formations, may have a strong influence on the measurements. The values recorded are, therefore, apparent resistivities (symbol R_a), generally different from the true resistivities.

The water saturation in the uncontaminated zone is given by equation 5, repeated below:

$$S = \left(\frac{F \times R_w}{R_t} \right)^{1/2} \tag{8}$$

with S_w = the water saturation in the uncontaminated zone; F = the formation factor; R_w = the resistivity of the interstitial (connate) water; and R_t = the true resistivity of the bed under study.

On Figure 14-5B the resistivity is represented as decreasing outwardly from R_{xo} to R_t in a water-bearing sand. This feature is general since the mud filtrate, R_{mf}, is usually more resistive than the connate water, R_w. For an oil-bearing formation, the curve is shown going up from R_{xo} to R_t; actually, the reverse trend ($R_{xo}>R_t$) is also very frequent wherever R_{mf} is considerably greater than R_w.

INSTRUMENTS, METHODS, AND THEIR APPLICATIONS

The standard Electric log, Microlog, Induction log, Laterolog, and Microlaterolog are discussed in the following sections.

Standard Electric Log

The standard electric log of today consists of two basic types of recordings: on the left side of the log appears the spontaneous potential of the borehole; the right side of the log is devoted to recordings of the electrical resistivities of the formations as encountered in the borehole.

There are various systems of measuring resistivities, but those most commonly employed are multi-electrode normal and lateral resistivity recordings. Generally the logs consist of two normal resistivity curves of different electrode spacings and one lateral curve. Any of these three resistivity curves can be presented in several scales to cover the full range of resistivities encountered in any particular borehole.

All modern logging equipment can simultaneously record the spontaneous potential curve and the various resistivity curves on at least two depth scales. The most commonly accepted depth scales are 2 inches = 100 feet and 5 inches = 100 feet. Occasionally a depth scale of 1 inch = 100 feet is recorded. On some specialized services, such as the Microlog or dipmeter, an expanded depth scale of 25 inches = 100 feet or 60 inches = 100 feet is frequently used. In very rare cases an expanded scale of 120 inches = 100 feet can be recorded.

Spontaneous-Potential Curve

The SP log (spontaneous- or self-potential log) is a record of naturally occurring potentials measured in the mud at different depths in a drill hole. Usually, the SP log consists of a base line, more or less straight, having excursions or peaks to the left (fig. 14-1). The base line corresponds in most cases to shales, whereas the peaks are generally opposite permeable strata. The shape and the amplitude of the peaks may be different, according to the formations; but there is no definite correspondence between the magnitude of the peaks and the values of permeability or porosity of the formation.

Measurement of SP

The recording of SP logs involves a simple technique. A measuring electrode is lowered in the hole at the end of an insulated cable. The differences of potential between a surface electrode which is at a fixed potential and the electrode in the hole whose potential varies as it is moved along the hole are observed by means of a recording galvanometer.

The drill holes in which the SP logs are recorded are usually filled with mud having a water base. The density of the mud is ordinarily such that at each depth the hydrostatic pressure in the hole is greater than the formation pressure. As a result, the fluid in the permeable beds cannot contaminate the mud at the time measurements are made. Also, the mud has been in constant circulation during the drilling operation which was prior to the logging and, therefore, is homogeneous.

Experience has shown that the deflections on the SP log correspond to phenomena occurring at the contacts between the mud and the different beds and also at the contacts between the beds themselves. These phenomena produce an electric current, called SP current, which uses the mud as its return path. In so doing, it creates in the mud, by ohmic effect, potential differences which can be measured and recorded.

Origin of SP

It is commonly accepted that the electromotive forces generating the SP current arise from two types of phenomena: electrochemical and electrokinetic.

The electrochemical phenomenon occurs at the contacts beween the drilling mud and the connate water in the pores of the permeable beds and the adjacent shales. Figure 14-6 shows schematically a permeable bed situated between the shales and penetrated by a drill hole filled with mud. The three media involved are the mud and/or the mud filtrate, the connate water, and the shales. These three media are separated by three boundaries across which three electromotive forces arise. As each medium is considered fairly homogeneous, each of the electromotive forces is uniform along its corresponding boundary.

Theory and laboratory experiments have shown that in clean formations the sum of the electromotive forces generated by the electrochemical phenomenon can be represented by the formula $E_c = -K\ log_{10}\ R_{mf}/R_w$, where R_w is the resistivity of the connate water contained, R_{mf} is the resistivity of the mud filtrate, and K is a constant. When the mud and the connate water contain essentially sodium chloride, factor K has been found theoretically equal to 80 at 150F, with E being expressed in millivolts. This result has been supported by field experience in many regions.

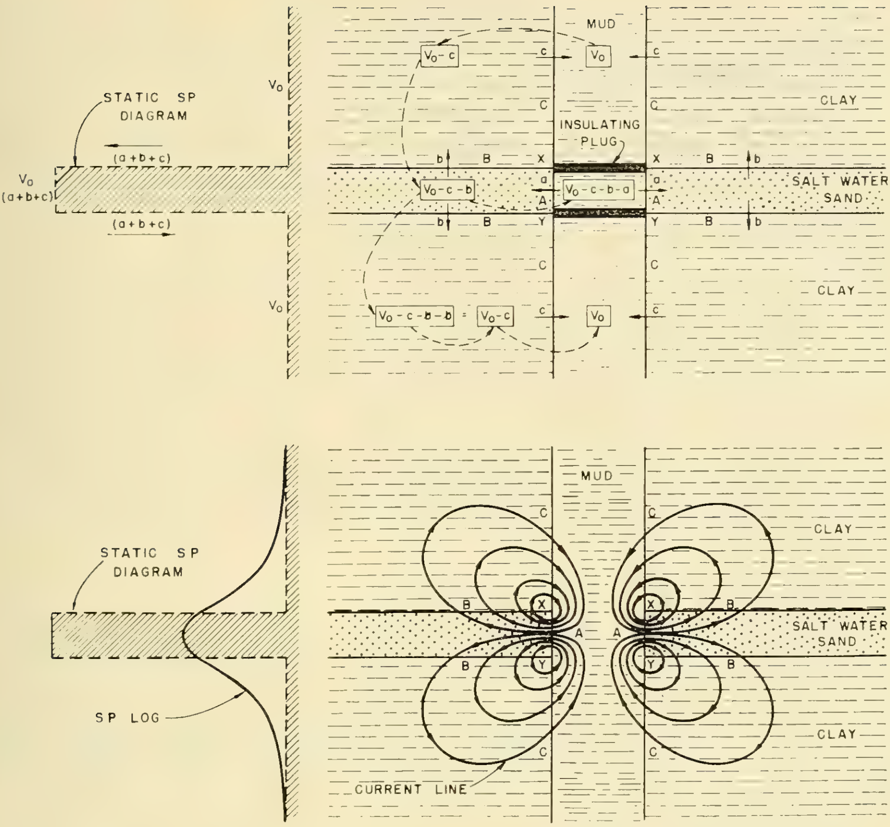
When the waters are very saline or contain other salts in solution, the R_w computed from the above formula will be too low. This value is called the equivalent resistivity, $(R_w)_e$; it can be corrected to true R_w by use of the inset chart. In formations containing shaly material, the above relations are no longer valid. This fact will be discussed later.

The electrokinetic phenomenon is caused by the infiltration of the mud filtrate into the permeable beds. This infiltration causes an electromotive force, E_k, to appear primarily where the pressure differential is at a maxium, i.e., across the mud cake. Since for a given formation the electromotive force depends on the nature of the filtrate and of the filter (mud cake) and on the pressure differential, it will be uniform all along the contact mud, permeable formations traversed by a drill hole.

Field experience has shown that in these regions where high salinity connate waters are the rule, as in the Gulf Coast, the amplitude of the electrokinetic *emf* (electromotive force) is generally small enough with respect to the electrochemical *emf* to be negligible.

Circulation of SP Current

The *emf's* of various origins add their effects to generate the SP current which follows the paths represented schematically in Figure 14-6 by solid lines. Each current line necessarily crosses the three boundaries. In the usual case where the resistivity of the mud is higher than the resistivity of the connate



a, b AND c: ELECTROMOTIVE FORCES ACROSS BOUNDARIES A, B AND C.

$\boxed{V_0}$, $\boxed{V_0 - c}$: POTENTIAL IN CORRESPONDING MEDIUM

— — — — —: STATIC SP DIAGRAM – POTENTIAL IN MUD WHEN SP CURRENTS ARE PREVENTED FROM FLOWING

————— SP LOG – POTENTIAL IN MUD WHEN SP CURRENTS ARE FLOWING

FIGURE 14-6. Schematic representation of current and potential distribution.

water, the current circulates in the direction of the arrows (from inside the borehole toward the permeable bed).

Along its path, the SP current has to force its way through a series of resistances, both in the ground and in the mud. Along a given line of flow, the potential decreases continuously in the direction of the current, as indicated by arrows; but across each boundary the potential increases by an amount corresponding to the value of the *emf* at the boundary. Along a closed line of current flow, the total of the ohmic-potential drops is necessarily equal to the algebraic sum of the *emf's* encountered.

Also, since the magitude of the current flow is constant all along its path, the potential drop varies according to the resistance of the section through which it flows. This means that the total potential drop is divided between the different formations and the mud in proportion to the resistances encountered in each respective medium. Accordingly, the potential drop in the mud of the drill hole is a measure of the greater part of the total *emf's* because the electrical resistance offered by the mud column is much greater than that offered by the formations.

Static SP

It is convenient to indicate the value of the *emf* forces which produce the SP currents by an idealized representation in which it is supposed that the SP current is prevented from flowing. Under these conditions the potential in the mud column when plotted would appear as shown as the dashed crosshatched curve on the left of figure 14-6. Since this is the maximum SP that could be measured, it is convenient to use this theoretical value as a reference; and it is called the static SP.

Factors Influencing Shape and Amplitude of SP Peaks

As shown in Figure 14-6, the current circulates in the mud not only opposite the permeable formation but also a short distance beyond its boundaries. As a result, although on the static SP diagram the boundaries of the permeable beds are indicated by sharp peaks, the SP log exhibits a more progressive change in potential extending along the drill hole beyond the boundaries of that bed.

An analysis of the circulation of the current shows that the bed boundaries are located at the inflection points on the SP log. This fact provides a means of accurately determining the thickness of a bed from the SP log.

Moreover, since the SP log records only that portion of the potential drop occurring in the mud, the amplitude of the peak of the SP log approaches the amplitude of the SP only when the resistance offered to the current by the bed itself and the adjacent formations is negligible compared with the resistance of the mud in the borehole.

The shape and the amplitude of the peak on the log opposite a given bed may be influenced by the following factors:

(a) The total electromotive forces involved (static SP); (b) the thickness of the bed; (c) the resistivity of the bed, of the surrounding formations, and of the mud; (d) the diameter of the drill hole; (e) the amount of invasion; and (f) the presence of interstitial shale. All other factors remaining the same, a change of the total *emf's* affects the amplitude but does not modify the shape of the SP log.

In practice, the *emf's* involved may vary from one hole to another because the salinity of the mud and/or of the formation waters is quite different. The amplitude of the *emf* also varies with the amount of shaly material inside the permeable bed. In a given hole, however, and for the same type of formations and for comparable depths, there is a definite tendency for the total *emf's* to be the same, provided the beds are all essentially clean.

Permeable beds of different porosity, or with different grain size, give the same *emf's*. The *emf's* are also independent of permeability, even down to fractions of one millidarcy.

It has been observed that the salinity is not always constant for all permeable beds pentrated by a hole, especially at widely different depths or in very different formations. Fresh-water sands or high-salinity sands will show low—or large—amplitude peaks, respectively. The polarity of the peak may even reverse when the water in the sand is less salty than the mud filtrate.

The manner in which the above-mentioned factors, besides the *emf's*, influence the SP will first be explained for the permeable beds between shales, as shown on Figure 14-7. In this example, the resistivities of the permeable beds are

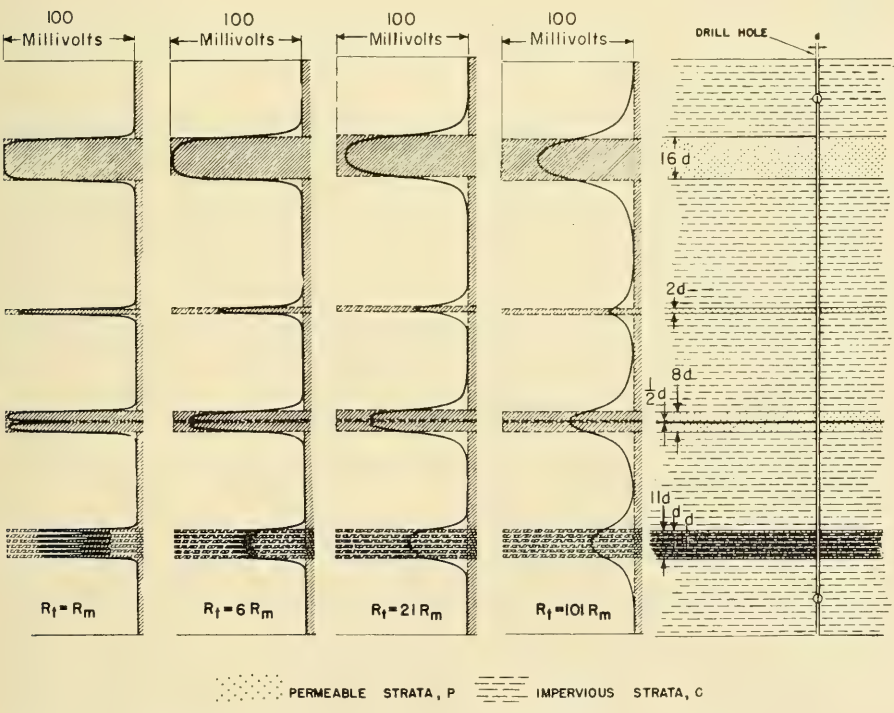


FIGURE 14.7. Comparison of SP for different values of $R_t R_m$.

generally greater than, or about equal to, those of the shales. This example is typical of the so-called soft formations such as sand and shale series. Shaly sands will be discussed later.

Permeable Beds Adjacent to Shales (Typical Example of Soft Formations)

Theoretical computations and field experience have shown that the amplitude of the SP deflection is practically equal to the static SP when the permeable beds are thick and when the resistivities of the formations are not too high with respect to that of the mud. Moreover, the SP curves mark the location of the boundaries of the bed with great accuracy.

The amplitude of the deflection is less than the static SP for thin beds: i.e., the thinner the bed, the smaller is the peak. On the other hand, when the resistivity of the formations is considerably higher than that of the mud, the SP curves are rounded off; the boundaries are marked less accurately. All other conditions being the same, the amplitude of the peak is less than when the ratio formation resistivity to mud resistivity is close to 1.

Figure 14-7 shows theoretical data illustrating the influence of the bed thickness and the resistivity of the formations. To facilitate the comparison, it has been supposed that the value of the static SP is the same for all beds and equal to -100 millivolts. Furthermore, for simplicity in the computations, the depth of invasion in the permeable beds has been supposed shallow enough to be negligible.

The SP curve (fig. 14-7) also spreads a considerable distance outside the boundaries of the layer when the ratio formation resistivity to mud resistivity is large: i.e., the higher the formation resistivity, the greater is this effect.

Figure 14-7 graphically shows the reduction of the recorded SP due to bed thickness and formation resistivity. Moreover, for a given static SP, the lower the mud resistivity, the smaller is the ohmic drop in the mud; and the wider is the deflection above and below the permeable beds. Conversely, the higher the mud resistivity, the sharper are the deflections.

An increase in hole diameter acts approximately like an increase in the ratio of formation resistivity to mud resistivity. It tends to round off the deflections on the SP log and to reduce the amplitude of the peaks opposite thin beds. A decrease in hole diameter has the same effect as a decrease in the ratio of formation resistivity to mud resistivity.

As shown on Figure 14-6, the permeable beds in general are invaded by mud filtrate. The electrochemical *emf's* originate at the boundary between the mud filtrate and the liquid in the permeable formations, somewhere inside the permeable formation. As a result, penetration of the mud filtrate into the permeable bed has an effect on the SP log similar to an increase in hole diameter: i.e., the SP peaks are wider than they would be in the case of no invasion, and the amplitude of peaks in thin permeable beds is smaller than for no invasion.

Shaly Sands

A combination of thin layers of sand in shale or of thin layers of shale in sand constitutes what has been called a sandwich; such a combination can be considered as a more or less shaly sand. One such example is illustrated in Figure 14-7. The following points must be mentioned concerning sandwich logs.

The average contour corresponding to a sandwich is the same as for a homogeneous permeable bed of the same thickness and resistivity but for which the total *emf* involved would be smaller. The amplitude of the ripples around the average curve decreases very quickly when the thickness of the individual beds is decreased. The ripples are hardly noticeable when the individual thickness of each of the sandwiched beds, both permeable and impervious, is less than one half of the diameter of the hole.

The average amplitude of the peaks decreases when the resistivity of the sand increases in comparison with that of the shale.

The term shaly sand has been applied above to interbedded thin streaks of sand and shale. There are also sand beds containing disseminated shales or clays, and many sands contain both stratified and dispersed shales. Whether the different shaly particles enclosed in a shaly sand are stratified or not, the mixture behaves in substantially the same way in the SP log. The total amplitude of the static SP is maximum for a clean sand, and it is reduced as the percentage of shaly material increases. In a shaly sand this total amplitude is called the pseudostatic SP or PSP.

If a shaly sand is thick enough, the deflection of the SP curve is equal to the pseudostatic SP. If the bed is too thin, the deflection is smaller than the pseudostatic SP, as a result of the same effect of geometry and resistivities as in clean sands.

The magnitude of the pseudostatic SP is a function of the resistivities of the uncontaminated zone in the shaly sand, of the invaded zone, and of the shales. Accordingly, the amplitude of the SP log can be expected to be smaller opposite the oil-bearing portion of a shaly sand than opposite the water-bearing section.

Because many sands are shaly, it is not surprising that a change in the deflection from the shale line on the SP log occurs very often when passing the oil/water contact in the sand. It is to be noted, however, that this change is not a positive criterion for the detection of oil since the same effect would be obtained if the salinity of the interstitial water were reduced or if the percentage of shale were increased.

Use of SP Curve for Evaluation of Connate-Water Resistivity

It has been seen that the SP is related to R_{mf}/R_w through equation SSP $=$ $-K \, log \, R_{mf}/R_w$. In this instance and when the mud and the connate water contain

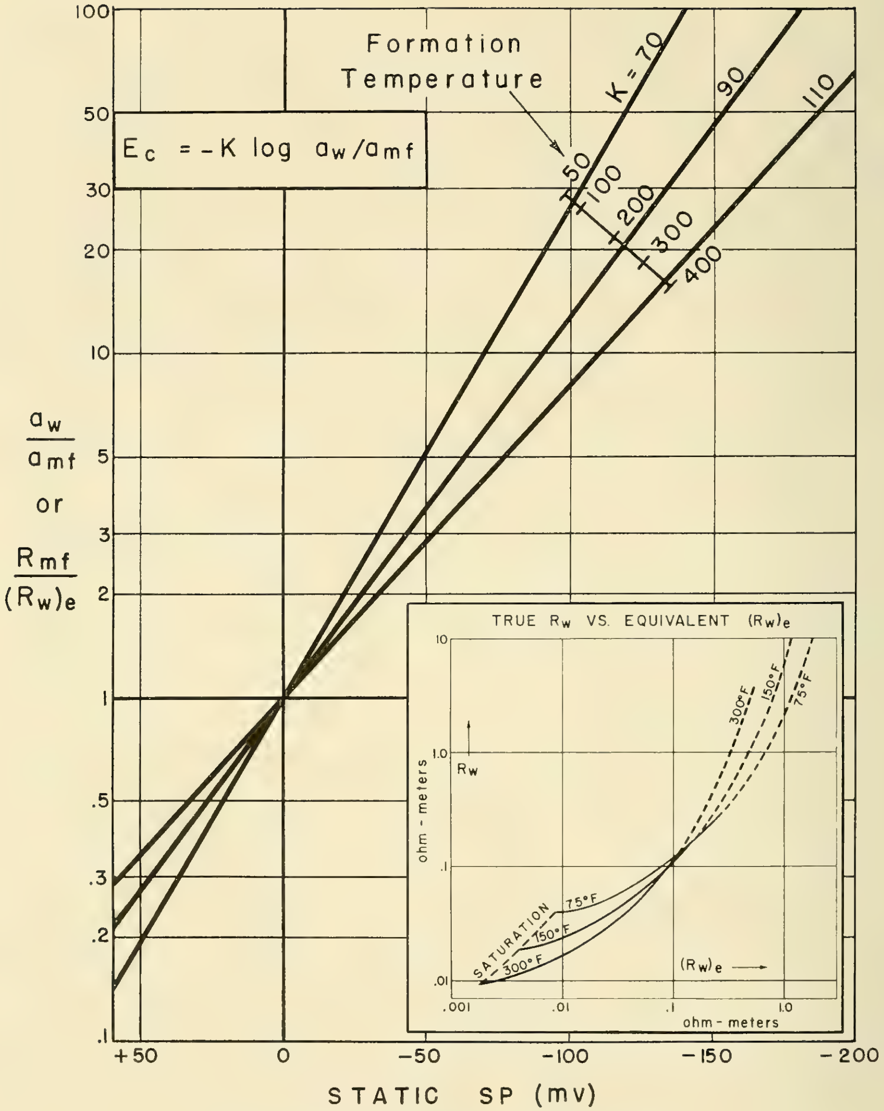


FIGURE 14-8. R_w determination from the SP.

essentially sodium chloride, R_{mf}/R_w can be generally obtained from a chart such as Figure 14-8.

Several curves are traced on Figure 14-8 corresponding to different values of the K coefficient. These values are the theoretical ones, computed for different temperatures.

After R_{mf}/R_w is obtained from the chart, R_w is easily derived from the knowledge of R_{mf}. Quite often R_{mf} is measured directly on actual samples of mud. If not, R_{mf} can be selected from average statistical values, as is shown on page A-4 of the Schlumberger Log Interpretation Charts.

In complex muds, the value of R_{mf} may be quite variable; and a direct measurement of R_{mf} is advisable.

In shaly sands, the SP deflection gives the pseudostatic SP which for the same values of R_{mf} and R_w is smaller than the static SP.

The application of the SP formula, using the pseudostatic SP, instead of the static SP, would give too high a value for R_w. This too-high value is called apparent connate-water resistivity and designated as R_{wa}. It should not be used as a basis for shaly sand analysis.

The reduction factor, the ratio $\dfrac{\text{Pseudostatic SP}}{\text{Static SP}} = \alpha$, is a convenient factor, which enters the formula for quantitative analysis of shaly sands.

Resistivity-Measuring Devices

If a single electrode A in the hole and a surface electrode B are connected across a source of direct or low-frequency alternating current, a current will flow between these electrodes through the hole and formations. If the hole electrode is surrounded by a homogeneous and isotropic medium, the current will flow radially from electrode A equally in all directions. This current will give rise to equipotential surfaces which are spheres centered around the electrode.

If another electrode M is introduced in the vicinity of electrode A and the potential measured between this electrode and another remote electrode N, the measured potential will be directly proportional to the resistivity of the medium surrounding the hole electrodes. This system is basically what is known as the normal resistivity.

If the remote-measuring electrode N is placed close to M relative to the AM distance, the potential difference between M and N is again proportional to the resistivity of the surrounding medium. This is basically the lateral resistivity.

The proportionality factors to convert the potential readings to resistivity are constant for any given electrode arrangement. Figures 14-9 and 14-10 illustrate the actual circuits used to measure the resistivity curves. In the normal resistivity circuit the current return electrode B is actually in the borehole for technical reasons. In the lateral circuit both arrangements shown will give the same results based on the theory of reciprocity. The latter, or MAB, system is the one used in actual practice.

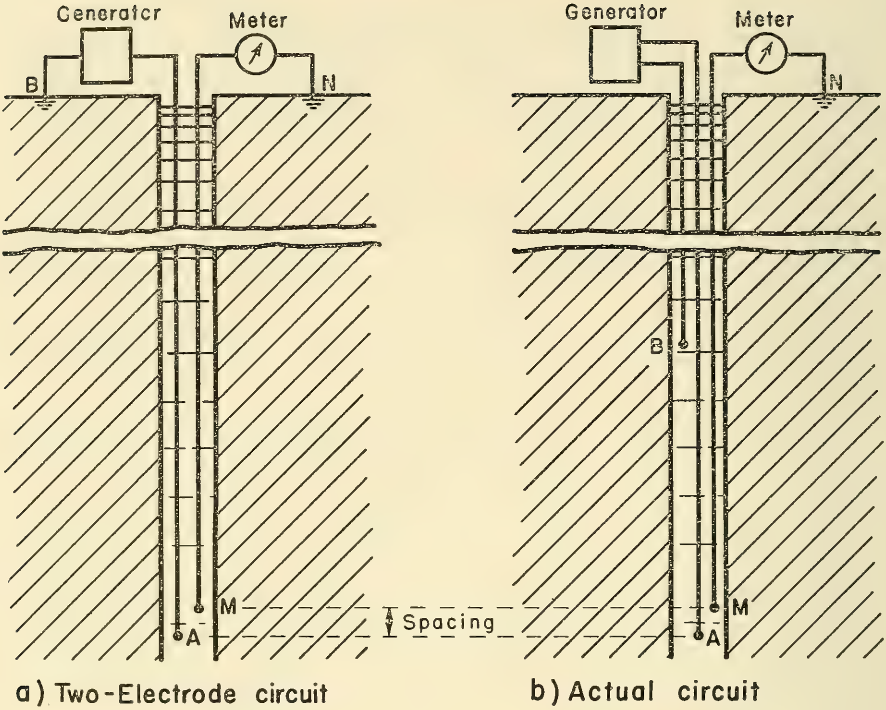


FIGURE 14-9. Schematic normal device.

Apparent Resistivity

Up to this point a homogeneous medium has been assumed. It is obvious, however, that in actual drill holes this condition does not exist. The existence of the borehole filled with mud, the inevitable nonhomogeneities in the formation, and the existence of an invaded zone in permeable formations are all factors that affect the current pattern surrounding the current electrodes A and the resulting potentials measured.

In a heterogeneous medium, then, the exploring device measures a quantity called the apparent resistivity. The apparent resistivity is an average value involving the resistivities of all the media surrounding the electrodes and depending on the arrangement and spacings of the device.

Radius of Investigation of a Device

The manner in which the various media surrounding the electrode affect the value of apparent resistivity obtained with a given device is sometimes indicated by reference to its radius of investigation. This characteristic is depend-

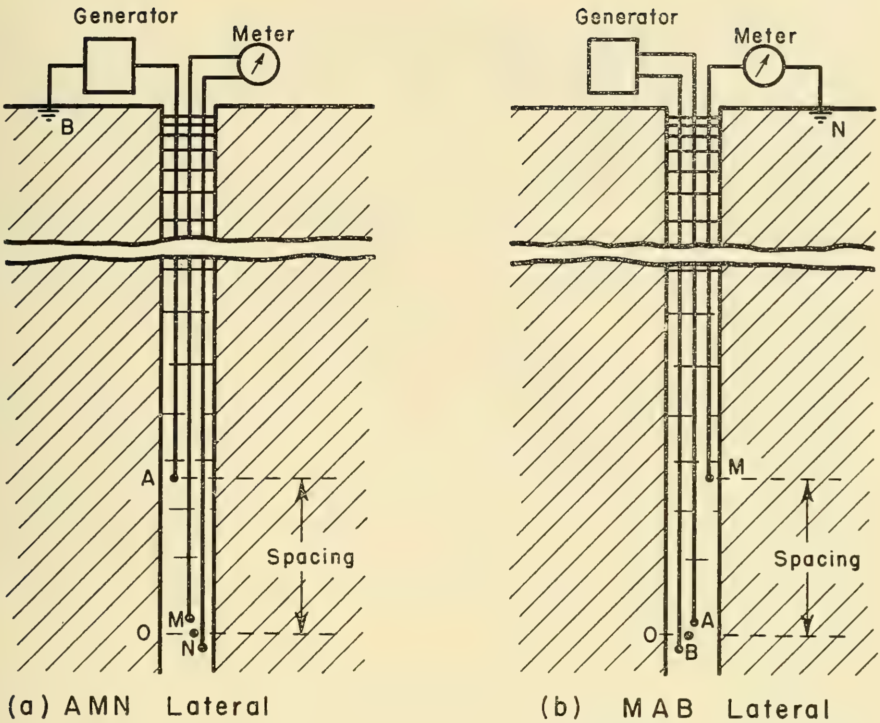


FIGURE 14-10. Schematic lateral device.

ent on the spacing of the device. When a very short electrode spacing is used, the mud in the hole may have a dominant effect on the value of resistivity obtained. If the spacing is increased, the volume of the media appreciably influencing the measurement increases; and the effect of the formations surrounding the mud column begins to become important. For large spacings, the resistivity of the surrounding formations becomes dominant.

For the determination of true formation resistivities, it is useful to record curves having large radii of investigation. This is particularly true in permeable formations which have been deeply invaded by the mud filtrate and which, therefore, have encircling the hole a zone whose resistivity differs from the true resistivity of the formation.

Electrode Combinations for Well Logging

The relative positions of the electrodes making up the sonde or exploring device lowered into the hole for the measurement of resistivity have a bearing on its general properties. Depending on the distribution of electrodes, a device may, for instance, be good for marking the thin breaks but may not give an exact representation of the thick layers, whereas another device that permits the estimation of fluid content may not be suitable for locating formation boundaries.

In early electric logging, a single resistivity curve was used. Later it was found best to use three different electrode arrangements together in order that the resistivity curves recorded may give as complete as possible a picture of all the formations encountered in the borehole, however different their characteristics may be.

The three resistivity curves of the conventional log are run respectively with a short normal device (AM = 16 inches), a long normal (AM = 64 inches), and a long lateral (AO = 18 feet 8 inches).

This combination of three curves with three different devices, however, does not always give all desirable information. Theoretical considerations and field experience have shown that using one or several other devices of the conventional type in addition to the standard ones does not help appreciably. A more complete and accurate definition of beds and a closer investigation of reservoir characteristics necessitate the application of the new methods described later (MicroLog and resistivity methods using focusing systems).

Curve Shapes - Laboratory Results

Figure 14-11 shows the curve recorded in the laboratory with *normal* devices for homogeneous resistive layers sandwiched between beds of low resistivity. The point of measurement of the readings is a point midway between A and M on the sonde.

Obviously, the curves are symmetrical with respect to the center planes of the layers. This is a general feature of the normal device. As a matter of fact, the same curves are recorded if M is above A instead of A above M as indicated in the figure.

The upper part of the figure illustrates a bed thicker than the spacing (bed thickness $e = 6d$; spacing AM $= 2d$; $d =$ hole diameter). It is observed that the boundaries of the bed are not sharply indicated on the resistivity log but tend to be rounded off owing to the influence of the drill hole. Moreover, the thickness of the bed, as indicated by the distance between the two points of inflection P and P′, on the curve, is less than its actual thickness by an amount equal to the spacing. The error in picking the boundaries of thick resistive beds is small for normal curves of short spacings, and this is one reason for the recording in practice of a short normal. It should be remembered, however, that normal curves tend to show resistive beds thinner than they actually are by an amount equal to the spacing. In a similar manner they tend to show conductive beds thicker than they actually are by an amount equal to the spacing.

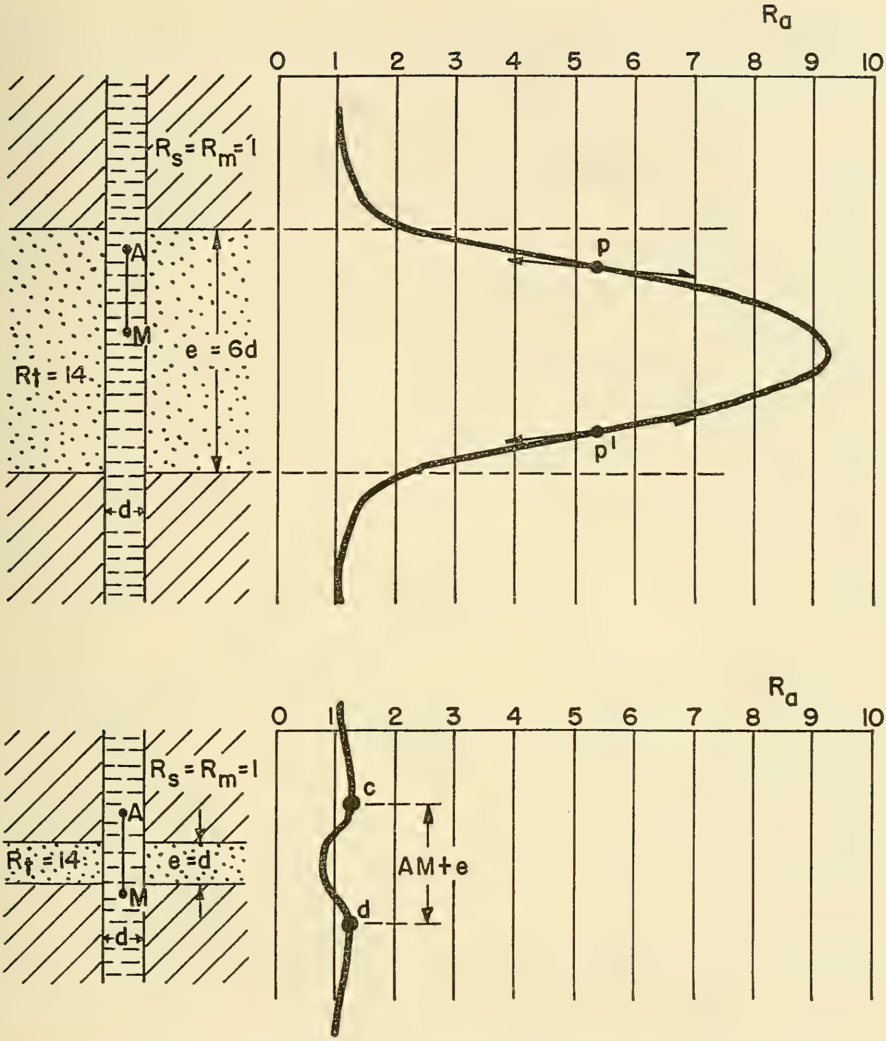


FIGURE 14-11. Response of normal device.

The lower part of the figure shows a resistive layer thinner than the spacing. This instance is characterized by a depression opposite the layer and two symmetrical small peaks, *c* and *d*, on each side of the depression. This feature illustrates the main disadvantage of the normal device: i.e., beds thinner than the spacing, no matter how resistive they may be, appear on the logs as being conductive.

In Figure 14-12 are shown the corresponding curves for lateral devices. The point of measurement of the readings is point O, midway between electrodes M and N.

In contrast to curves recorded with normal sondes, the lateral curves are markedly dissymmetrical with respect to the center planes of the layers; and their features are considerably more complex. As before, the transitions in the curves corresponding to formation boundaries have been rounded off by the effect of the drill hole.

It is observed that, for a bed thicker than the spacing, the upper boundary of the bed is not well defined on the lateral curve; and, as a whole, the bed appears to be displaced downward. The amplitude of the shift is approximately equal to the spacing.

The lower part of Figure 14-12 corresponds to a resistive layer thinner than the spacing. The bed is indicated by a sharp peak of comparatively low apparent resistivity. A slight depression is observed above the layer, followed by a second smaller peak located at a distance below the bottom boundary of the layer equal to the spacing. This secondary peak is called a reflection peak, and the zone of very low apparent resistivity is called the blind zone. The blind zone corresponds to the interval during which the resistive streak is located between the current electrode and the measuring electrodes.

The lateral is useful for the location of thin, highly resistive streaks, although the interpretation may be difficult if several resistive streaks are close together; a lower streak located in the blind zone of an upper resistive streak may be missed; and the reflection peaks may be mistaken for actual resistive streaks in the formation.

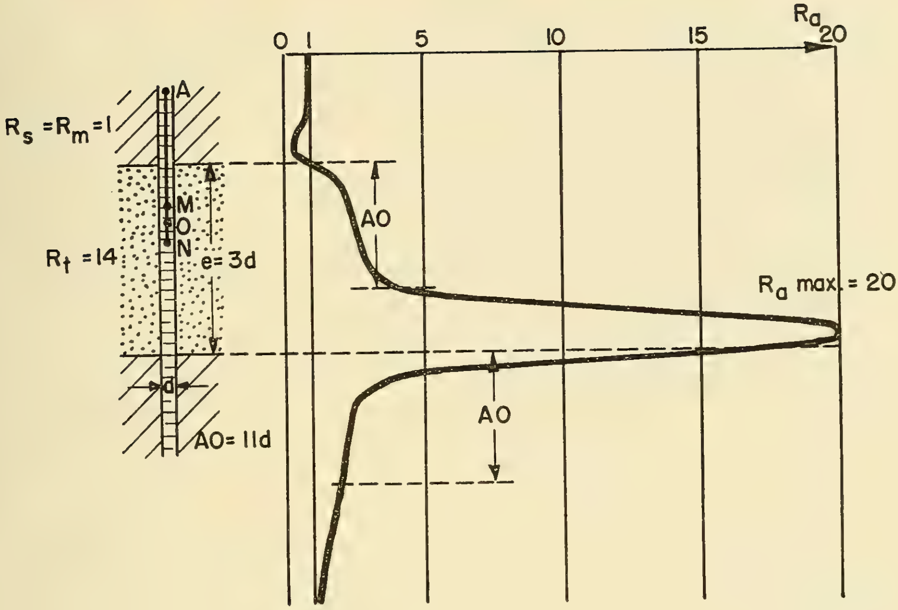
For a resistive layer whose thickness is approximately the same as the spacing (critical thickness), the curve is almost completely flattened.

Similar generalizations are possible for lateral curves recorded for beds more conductive than the surrounding formations. Whether the layer is thick or thin, the shape of the curve is dissymmetrical; and the anomalies are spread downward, outside of the bottom boundaries. The apparent increase of thickness is roughly equal to AO.

Resistivity-Departure Curves

It has already been pointed out that the apparent resistivity, measured by a given device in a drill hole, is dependent on the resistivities of all the different media in the vicinity of the electrodes and may thus differ considerably from the true resistivity of the formation being logged.

The evaluation of the fluid content of permeable beds from electric log data requires a knowledge as accurate as possible of the true resistivity of the beds. Resistivity departure curves have been computed in order to help derive



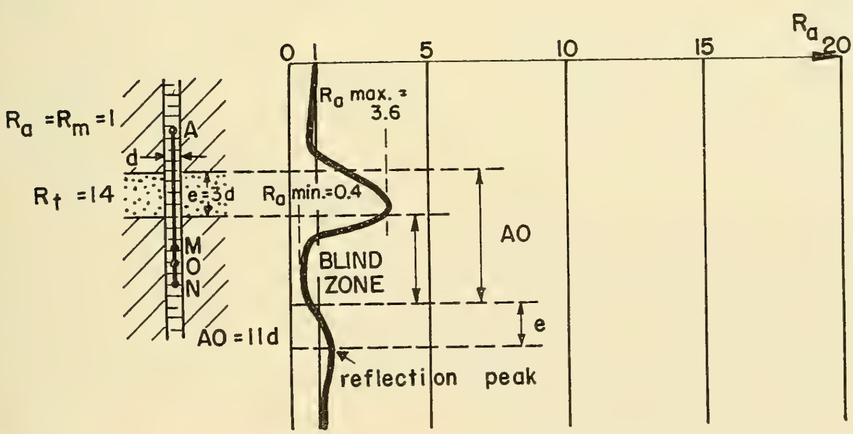


FIGURE 14-12. Response of lateral device.

the value of the true resistivity from the apparent resistivities read with the conventional devices.

The curves show the departure of apparent resistivity from true resistivity as a function of the various related parameters.

R_t = the true resistivity of the formation
R_m = the resistivity of the mud in the drill hole opposite the formation
d = the diameter of the drill hole
AM or AO = the spacing of the device used to make the measurement
e = the thickness of the bed (in a bed of finite thickness)
R_s = the resistivity of the adjacent beds (in a bed of finite thickness)
R_i and D_i = parameters determining the invaded zone. (In the computation of the curves, the invaded zone is supposed to be a homogeneous medium of resistivity R_i, separated from the uncontaminated zone by a cylindrical surface of diameter D_i, co-axial with the borehole)

In the presentation of the charts, the effective number of variables is reduced by using the diameter (d) of the drill hole as the unit of length and the resistivity of the mud (R_m) as the unit of resistivity. The list of variables is thus shortened to R_a/R_m, R_t/R_m, R_i/R_m, R_s/R_m, AM/d, or AO/d, D_i/d, and e/d. The curves are grouped on the charts according to whether they correspond to normal or to lateral devices, according to whether they correspond to beds of infinite thickness or to beds of various finite thicknesses, and according to the conditions of invasion.

The resistivity departure curves are not of great help for the estimation of R_t in thin beds (thickness less than about 15 feet, 20 feet when bed resistivity is moderate) because the effect of the adjacent formations on the readings made opposite the beds is so great that the curves have practically no resolution. The curves are useful for thick beds, provided the value to be taken for R_i is approximately known (this value may be equal to R_{xo}, as given by the MicroLog or MicroLaterolog) and that some reasonable hypothesis can be made on the depth of invasion. In general the departure curves are valuable to assess the respective influence on the apparent resistivities of the factors involved and to determine what response should be expected from the various measuring devices in each given condition.

Application of Conventional Electric Log

In sand-shale series, geological strata generally form long sequences of thin sand and shale layers. Usually a sand line and a shale line can be traced on the SP logs showing that many sands are practically clean of shaly material and that many shales do not contain an appreciable amount of sand.

The SP curve and the short normal curve give a good record of the boundaries of the shale and sand beds provided they are thick enough. The very thin breaks within sand bodies are shown only by minor changes on the curves.

Moreover, very thin hard beds in shale formations, which are rather poorly indicated by the SP logs, show up sufficiently clear on the short normal curve recorded with an amplified scale to be useful as markers for correlations.

Generally, the resistivity of the mud is much greater than that of the connate water; on the Gulf Coast, for example, the mud resistivities at formation temperature are confined to a range from about 0.5 to 2 ohm-m, whereas the resistivities of the connate water are generally lower than 0.05 ohm-m. The resistivity of the invaded zone is, therefore, much higher than the true resistivity of the water-bearing formations and often exceeds the true resistivity of the oil-bearing formations. The apparent resistivity measured with the short normal is greatly affected by the invaded zone; and peaks are generally obtained on the log in front of the permeable beds, even if their true resistivity is very low. Sometimes, however, the depth of penetration of the mud into the permeable layers is small enough so that the short normal curve is very little affected and shows low readings in front of the conductive layers.

In soft formations of high porosity, the readings of the long normal generally are little influenced by the mud and the invaded zone. Wherever the bed thickness is great enough, a conductive bed is marked by a low apparent resistivity, whereas a resistive bed gives rise to a high resistivity, sometimes higher than the reading obtained with the short normal. Again for thick enough beds, the comparison between the short and the long normal curves frequently indicates whether the bed is invaded by mud filtrate: i.e., if it is permeable. The beds, whose thickness is about equal to or lower than the spacing, are very poorly shown by the long normal curve.

The lateral curve opposite thick resistive beds is distorted, with a maximum reading obtained in the lower portion of the bed. Sharp peaks are generally obtained at the level of thin resistive beds, but the definition of these beds with the lateral curve is often obscured by the presence of blind zones and spurious peaks. Yet in deep invaded formations, such as hard-rock formations, only the long lateral is able to give a reading not greatly affected by mud invasion. A much more accurate definition of the boundaries of permeable beds, shales, and hard streaks is obtained when the MicroLog is run together with the conventional log.

MicroLog

A MicroLog is a resistivity log recorded from three electrodes arranged in a vertical line, one inch apart, on a rubber pad. This pad is pressed against

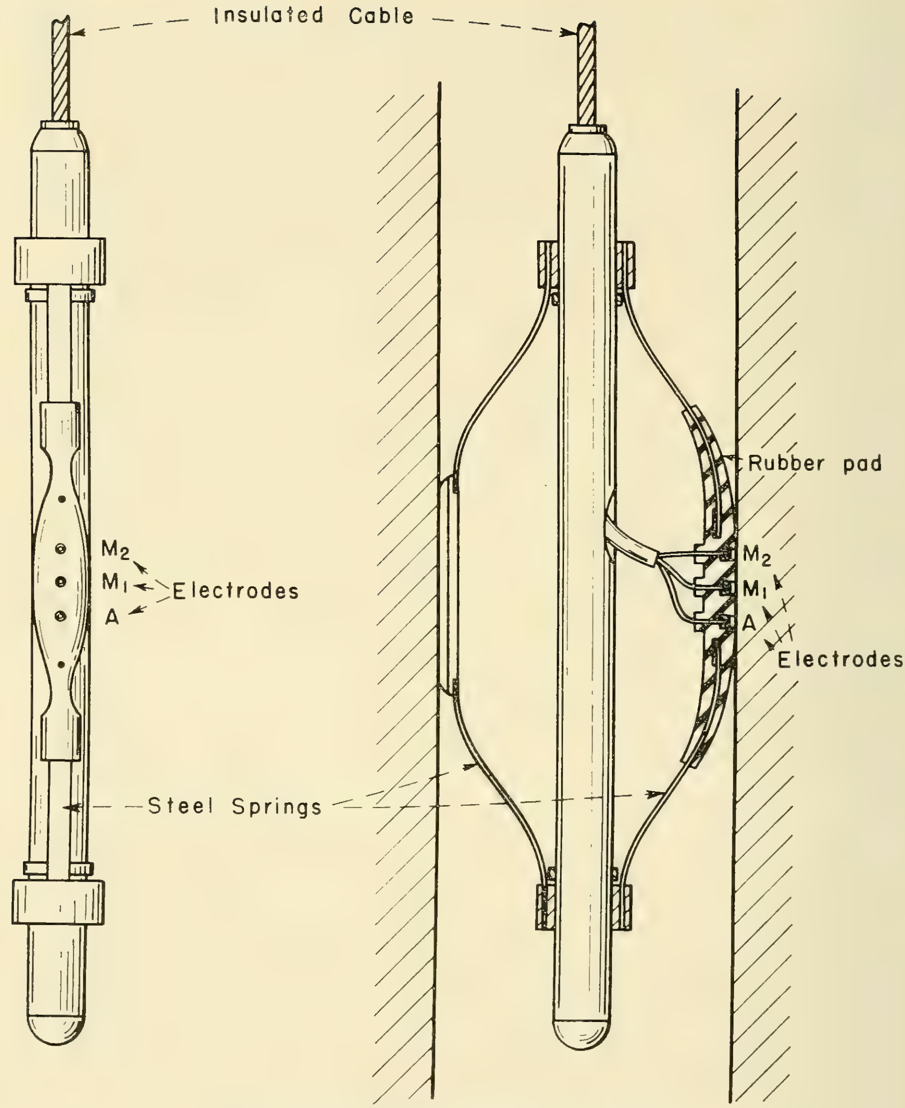


FIGURE 14-13. Schematic micrologging device.

the wall of the drill hole. The pad reduces the short-circuiting action of the mud, and the electrodes measure the average resistivity of a small volume of material at the face of the borehole (fig. 14-13).

Two resistivity measurements are made by sending a current of known intensity through elecrode A and recording the potential difference created, on the one hand, between electrodes M_1M_2 and, on the other hand, between electrode M_2 and a reference electrode at the surface. The combinations AM_1M_2 and AM_2-surface are generally referred to as microinverse and micronormal systems, respectively. The volume of ground involved in the measurement is smaller for the microinverse than for the micronormal; in other words, the microinverse has a smaller radius of investigation.

An SP curve may be recorded simultaneously with the MicroLog.

The most recent equipment includes a second pad, identical and diametrically opposed to the first. The distance between the outer faces of the two pads is continuously recorded, providing the so-called microcaliper log. The microcaliper log is very accurate and can measure variations of hole diameter as small as 1/8 inch.

Delineation of Different Formations — Porous and Permeable Beds

When the pad is applied to a porous and permeable bed, the mud cake represents an important proportion of the small volume involved in the measurement. The resistivity of the mud cake can be estimated to be usually at most twice the resistivity of the mud in water-base mud and somewhat more in oil-emulsion mud. The other part of the volume measured is the formation which, according to laboratory experiments, extends about three inches from the wall. Usually, the fluids originally present in this fraction of formation have been almost completely flushed by mud filtrate, except when invasion is very shallow; and the resistivity of this flushed zone is directly related to that of the mud. The resistivity measured opposite a porous and permeable bed, therefore, does not exceed a few times the resistivity of the mud. Fifteen or twenty times the mud resistivity is a maximum for the resistivity measured opposite a porous and permeable bed in fresh mud.

Because of its smaller depth of investigation, the microinverse is more influenced by the mud cake than is the micronormal. The values read with the two different electrode arrays are therefore usually different. The difference between the two readings is called separation. Usually the resistivity of the flushed zone is greater than that of the mud cake, therefore the micronormal gives a higher apparent resistivity than the microinverse, and the separation is said to be positive.

Accordingly, the criteria for the interpretation of porous permeable beds are the following:

1. Comparatively low resistivity readings, not more than 20 times the mud resistivity (in fresh mud).
2. Positive separation between the microinverse and the micronormal as long as a substantial mud cake is deposited.

An important exception to the second rule occurs when the invasion is very shallow and the formation is salt water bearing. The depth of invasion may be so small that the volume of formation involved in the resistivity measurements includes a portion of the formation beyond the flushed zone. Under such conditions the mud cake is more resistive than the formations immediately behind, and the micronormal reading is lower than the microinverse. In other words, the separation is negative. Shallow invasion is prevailing whatever the type of mud when the porosity and vertical permeability are very high and in fissured formations where the matrix is not flushed. Also, instances of no separation can occur when the mud cake is fairly thin, especially in zones of high porosity.

It can be added that the effect of the mud cake is to level out the resistivity readings, so that the curves never show sharp variations opposite a permeable bed, even when the formation factor changes appreciably within the bed. The same criteria apply in granular porosity, as well as in well-distributed secondary porosity.

The above discussion shows that the MicroLog can detect the permeable beds even with very low permeability provided it is sufficient for the mud cake to build up. Therefore, a bed may be indicated by the MicroLog as being permeable, whereas the permeability is too low for commercial production.

Tight Sections

In tight sections the electrode system is separated from the formation only by a thin mud film, maybe 1/16 inch thick or less. The MicroLog readings accordingly are very high, at least equal to 20 times the mud resistivity. The mud film, furthermore, does not have a constant thickness because the wall of the hole is not perfectly smooth. Depending on the depth of the irregularities in the hole wall, the path offered to the current to escape toward the mud column is variable. As a result, the curves show numerous sharp peaks and depressions; and the separation may be positive or negative.

Shales

When there is no caving in the shales, the pad again is separated from the formation by a thin mud film. The reading is equal to, or more often smaller than, the resistivity of the shales. The separation may be negative, nil, or slightly positive. This behavior of the MicroLog in shales is not entirely explained. It is assumed that the occurrence of negative separation may be due partly to the anisotropy of the shales.

In practice, when a positive separation is observed opposite a shale, a confusion is possible with a permeable bed. It is then indispensable to use other curves to solve the ambiguity. In many instances the SP curve is sufficient. Very often, however, these curves do not give clear enough indications opposite very thin beds. The microcaliper is extremely helpful in general since a decrease in hole diameter is likely to correspond to the presence of a mud cake, and, hence, of a permeable bed.

Hole Enlargements

Caving is most often encountered at the level of shale beds but may occur also opposite other types of formations. In this instance the pad generally does not apply to the wall. When the caving is deep, the two readings are equal to the mud resistivity. The fact that the MicroLog curves read a resistivity that is equal, or close, to the mud resistivity is usually a conspicuous indication of the presence of a cave. In many instances, however, the interpretation is not so easy. If the cave is not too deep, the readings may still be affected by the formations; and, since the mud is usually less resistive than the formations, a positive separation is observed; and again a confusion is possible with permeable streaks. As in the preceding example, the ambiguity can be solved with the help of the SP curve and the microcaliper.

Mud Log

When the MicroLog pad is not extended, the curves are greatly influenced by the mud. If parts of the hole are large enough, the microinverse will read a value which equals the resistivity of the mud at that level in the hole. Often this value is more accurate than that obtained from a surface sample of mud.

Use of MicroLog in Quantitative Analysis

In water-bearing formations the flushed zone is practically saturated with mud filtrate. If the formation is clean, the formation factor can be taken equal to R_{xo}/R_{mf}, R_{xo} being the resistivity of the flushed zone and R_{mf} the resistivity of the mud filtrate. Porosity is deduced from the formation factor.

The presence of the residual oil saturation in the flushed zone affects the measurements, and a corresponding correction is necessary. To this end, the proportion of residual oil has to be surmised. Taking a value of 20 percent for the residual oil saturation would not usually entail too big errors, at least in formations with granular porosity and in light oils. Greater residual oil saturations are, however, frequent, chiefly in highly viscous oil. Gas-bearing formations also seem to display high residual saturations in the flushed zone because of the segregation effect if good permeability exists. Because of these residual saturations, the MicroLog may show water contacts.

The value of R_{mf} can be measured directly if samples of filtrate are available. If this cannot be done, R_{mf} can be estimated from the value of R_m, the mud resistivity, according to average statistical data obtained in the laboratory. The evaluation of the formation factor and, hence, of the porosity finally depends on the determination of R_{xo}.

Except in very shallow invasion, the radius of investigation of the MicroLog does not extend beyond the flushed zone. The measured resistivities are functions of the resistivity R_{xo} of the flushed zone, of the hole diameter d, of the resistivity R_{mc} of the mud cake, and of the thickness t_{mc} of the mud cake. Interpretation charts that have been established on the basis of laboratory determinations make possible the derivation of the value of R_{xo} and t_{mc} from the two MicroLog readings, provided the values of d and R_{mc} are known. The hole diameter is generally known from the bit size or, better, from a section gauge or a microcaliper log. The value of R_{mc} can be obtained, as for R_{mf}, by direct measurements on mud cakes pressed from actual samples of the mud or from average statistical data.

When R_{xo} is not too great in comparison with R_{mc}, as in high porosity formations, the MicroLog readings are not too much affected by the presence of mud cake; and R_{xo} can be obtained with a fair accuracy. The reverse situation occurs when R_{xo} is very great in comparison with R_{mc}, low porosity. Thus, there is a lower limit of porosity values under which the quantitative interpretation of the MicroLog is not too reliable. With the hydraulic type of pad, the limit is about 12 to 15 percent, depending on the character of the mud cake.

In those formations where it can give R_{xo} with enough accuracy, the MicroLog is also valuable for the determination of water saturation. The knowledge of R_{xo} is helpful to correct the readings of the standard devices, if necessary, for the effect of invasion.

Induction Logging

Induction logging is a method wherein the conductivity, or its reciprocal the resistivity, of the formations is measured by means of induced current without the aid of electrodes.

The main advantages of induction logging over the conventional methods are the following:

a. The induction log gives a sharper delineation of the interfaces between different values.
b. It makes possible a more accurate determination of the true resistivity of thin beds, especially when the resistivity of the bed is lower or only slightly higher than the resistivity of the adjacent formations.
c. Induction logging can investigate the uncontaminated zone of permeable beds behind a highly resistive invaded zone, as in low-porosity formations drilled with comparatively fresh mud.

Furthermore, induction logging is appropriate to resistivity measurements in empty holes or in holes that are drilled with oil-base mud.

Principle

In this method of logging, the formations surrounding the logging apparatus are energized by electromagnetic induction. An alternating current is made to flow through a transmitter coil. The alternating magnetic field due to this current induces eddy currents in the earth surrounding the coil. These eddy currents in turn have their own magnetic field, which induces an electromotive force in a receiver coil.

If the transmitter current is kept constant, the magnitude of the eddy currents is proportional to the conductivity of the earth and, consequently, inversely proportional to the earth resistivity.

Figure 14-14 shows schematically a simple induction logging system in which a transmitter coil and a receiver coil are wound co-axially on a supporting insulating mandrel. The distance between the coils, designated in the figure as L, is called spacing.

An alternating current of constant magnitude and frequency is fed to the transmitter coil from an oscillator which, with the amplifier, is actually housed in an electronic cartridge above the coil system.

The voltage induced in the receiver coil by linkage with the magnetic field of the eddy current is fed into an electronic system where, after being amplified, it is rectified into direct current for transmission to the surface, where it is recorded. In logging, the point of measurement is taken to be a point midway between the coils.

In addition to the two coils referred to above, designated as the main coils, the apparatus used in practice includes several additional coils. The characteristics of the main coils and of the additional coils, their distribution, and their respective positions are adjusted in order to minimize the influence on the measurements of the mud column and of the media located above and below the instrument. Such types of apparatus are called focusing sondes.

The most usual types of instruments in the field at the present time are the 27-inch and the 40-inch focusing sondes. The former has a lesser radius of investigation but a slightly better vertical resolving power than the second.

Scaling

Some of the scales used for the presentation of the induction logs are different from those of other logs. Inasmuch as the signal measured is proportional to the conductivity of the formations, the induction log is scaled in terms of conductivity.

The conductivity scale is linear and is referred to a zero line located at the right side of the log so that the deflections of the curves toward the left correspond to increases of conductivity.

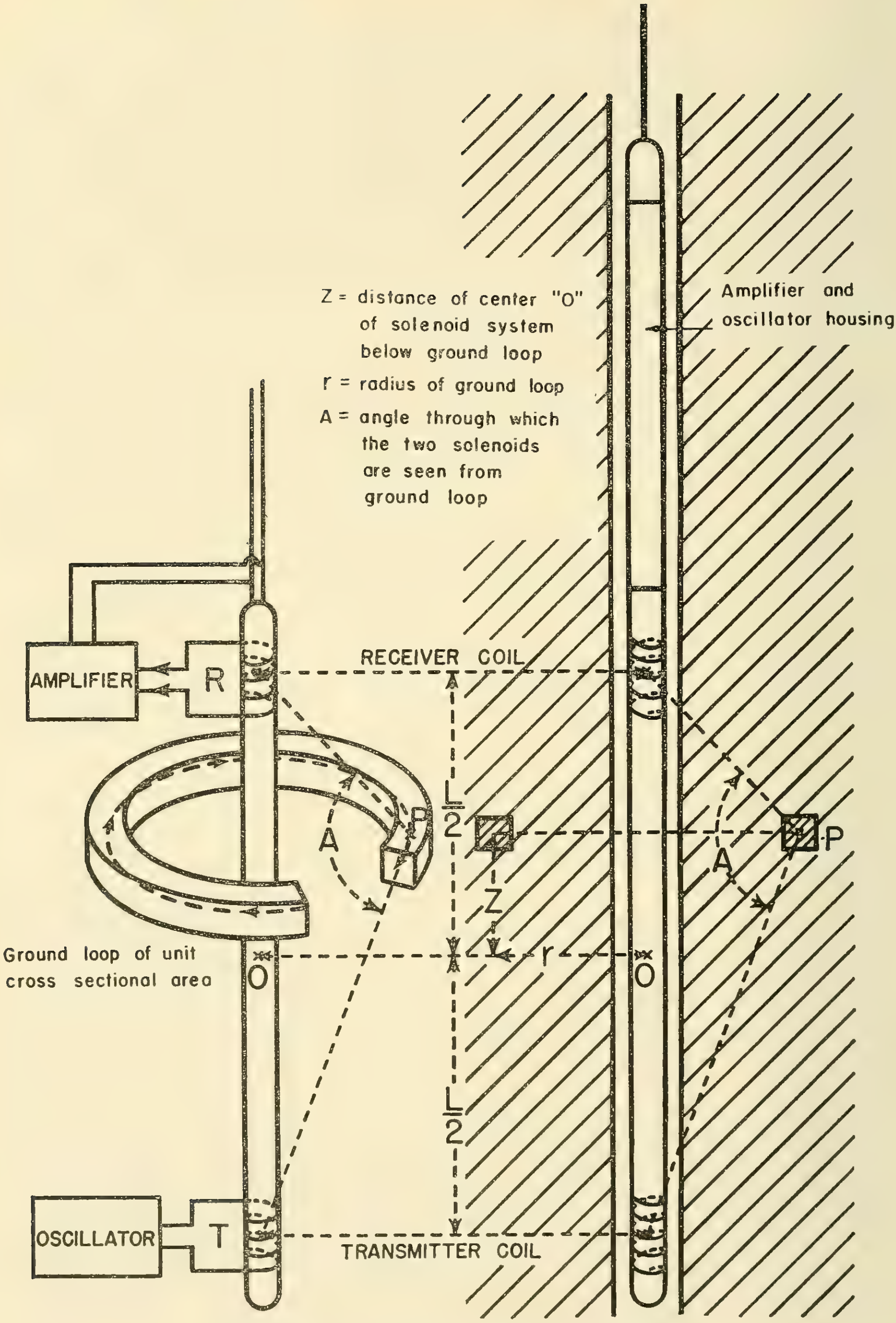


FIGURE 14-14. Schematic induction log device.

The unit of conductivity is the mho/m, reciprocal of ohm-m. In order to avoid decimals in the evaluation of conductivity, the millimho/m is usually used as a practical unit. For example, if formations have resistivity values of 1, 10, and 100 ohm-m, the corresponding conductivity figures will be 1000, 100, and 10 mmhos/m respectively. Resistivities (ohms) = 1000/Conductivities (millimhos).

The scale, if counted in terms of resistivities from the left to the right, is hyperbolic. Therefore, the low resistivities are emphasized, and the high resistivities are compressed.

On many induction logs, an additional reciprocated curve is recorded simultaneously. This curve, which gives the same measured values but with a linear resistivity scale, makes possible an easier comparison of the induction logs with the conventional logs.

In order to conform to the usage of electrical logging, the factor resistivity rather than conductivity will be generally considered in the following discussion.

Interpretation

The definition of different beds and the determination of their boundaries are easier and more accurate with the induction log than with the conventional logs. Sharp deflections occur exactly at the levels of the boundaries, and the curve opposite a given bed shows practically no distortion. Good definition can be obtained for thin beds down to a thickness of about 4 feet. Besides, the hyperbolic resistivity scale brings the details quite conspicuously to light; the lithological variations and the oil-water contacts are shown by large deflections of the curve.

Effect of Mud Column

The signal contributed by the mud column has been eliminated in most instances. The 40-inch induction is not influenced by the mud column when centered in holes of less than 12 inches in diameter. When not centered, the effect of the mud column is negligible in fresh muds. In low-resistivity muds or in high-resistivity formations, the induction tool, if not centered, must have at least a 1-inch standoff.

Effect of Bed Thickness

With induction logging, the measurements made at the level of a given bed are much less affected by the adjacent formations than with the conventional resistivity logs, all other conditions being the same.

For a given bed thickness, the influence of the adjacent formations is quite different, depending on whether they are more or less resistive than the bed. This difference comes from the fact that the eddy currents induced in the earth have a tendency to circulate through the most conductive media. If the resistivity of the adjacent formations R_s is greater than the resistivity R_t of the bed, the eddy currents concentrate within the boundaries of the bed. The signal contributed by the adjacent formations is then comparatively small. Computations and experience show that, in this instance, the measurements are practically unaffected if the thickness of the bed is 6 feet or more. Approximate charts have been computed for thinner beds.

If a reservoir contains thin resistive streaks, such as lime or lignite beds, the readings made opposite the porous and permeable sections of the reservoir are not essentially affected by the presence of these streaks, which cause important distortions on conventional logs.

Effect of Invasion

In contrast with the other resistivity methods, the induction log is at its best for the investigation of permeable beds when R_i is greater than R_t. In this instance, most of the eddy currents flow in the uncontaminated zone, whereas when R_i is smaller than R_t they flow mostly in the invaded zone. For a given value of D_i, the proportion contributed by the uncontaminated zone to the measured signal is greater in the first than in the second instance; in other words, the measurement in the first instance is closer to the true resistivity.

For obtaining the most accurate results with the induction log, the mud resistivity R_m should preferably be at least 10 times as great as the connate-water resistivity R_w. This condition is fulfilled most of the time in those regions where connate waters are very saline. The interpretation is still possible, even if R_m/R_w is as low as 5, as is frequently the case when connate waters are comparatively fresh.

In short, it can be said that the effect of the invaded zone is negligible when R_m/R_w is at least equal to 5 if the diameter of invasion does not exceed about 20 inches. Approximate charts are also available to correct for the effect of invasion, provided the diameter of the invaded zone is known or can be reasonably surmised.

Sand and Shales (Water-Base Mud)

In these formations, the resistivity R_t of the reservoirs is generally not too great with respect to those of the adjacent formations. According to the above, the induction log will usually give a direct record of the true resistivities when the mud is not too saline, when the beds are not exceedingly thin (at least 5 feet), and when invasion is reasonably shallow (diameter of invasion not greater than 20 inches).

These conditions are very often encountered in sand-shale series. In the instances where they are not fulfilled, the readings can be corrected for the effects of the borehole and of the adjacent formations. Since the diameter of invasion generally is not known, the correction for its influence requires one additional measurement by another suitable device. The short normal can be used for this. The value of R_t can then be derived from the readings of the induction log and of the short normal by means of interpretation charts. In this procedure, the knowledge of R_{xo}, the flushed zone resistivity, is necessary (R_{xo} is determined by the MicroLog or the MicroLaterolog; it can also be derived from the value of porosity obtained from other sources). These charts, at the same time, give a good estimate of the depth of invasion.

If the value of R_t cannot be determined exactly because the invasion is too deep and/or the bed is too thin, the approximation obtained from the induction log is most often sufficient to provide a sound basis for the estimation of fluid content, at least qualitatively.

Field Examples

Figure 14-15 is a composite example showing the induction log, the conventional resistivity logs, and the MicroLog run in unconsolidated sand-shale series, including a few hard streaks (Gulf Coast).

The ability of the induction log to delineate the variations of resistivities within highly conductive sections is clearly indicated over sections E and H.

The advantage of induction logging over the conventional log to determine true formation resistivities, particularly opposite thin beds, is also illustrated by this example. Considering bed A, the thickness of which is about 8 feet according to the MicroLog, it is obvious that the long normal reading is influenced by the more resistive adjacent formations (shales: resistivity 1.5 to 1.8). The short normal reading is somewhat higher because of an invaded zone, which is more resistive than the uncontaminated zone (the mud resistivity is 1.1 at BHT). Furthermore, bed A is located within the blind zone of the lateral curve due to a thin resistive streak above; and the reading is much too low (less than 0.5). Finally, there is no doubt that the induction log reading (0.8) is closest to the true values.

Over intervals B and C, the long normal curve is distorted by the thin highly resistive streak in between. As the thickness of this streak is smaller than the spacing (i.e., 64 inches), the curve shows a depression at its level; and the resistivities recorded just above and below (i.e., precisely opposite the two beds B and C under investigation) are spuriously increased. The long normal reads 1.5 and 1.8 ohms, respectively, opposite the two beds, whereas the induction log readings, which are practically unaffected by the hard streak, are 0.8 and 0.7. Here again the short normal curve is influenced by the invasion, and bed C is located in the blind zone of the lateral curve. Similar remarks can be made for the other thin beds in the section, such as D, F, G, and I.

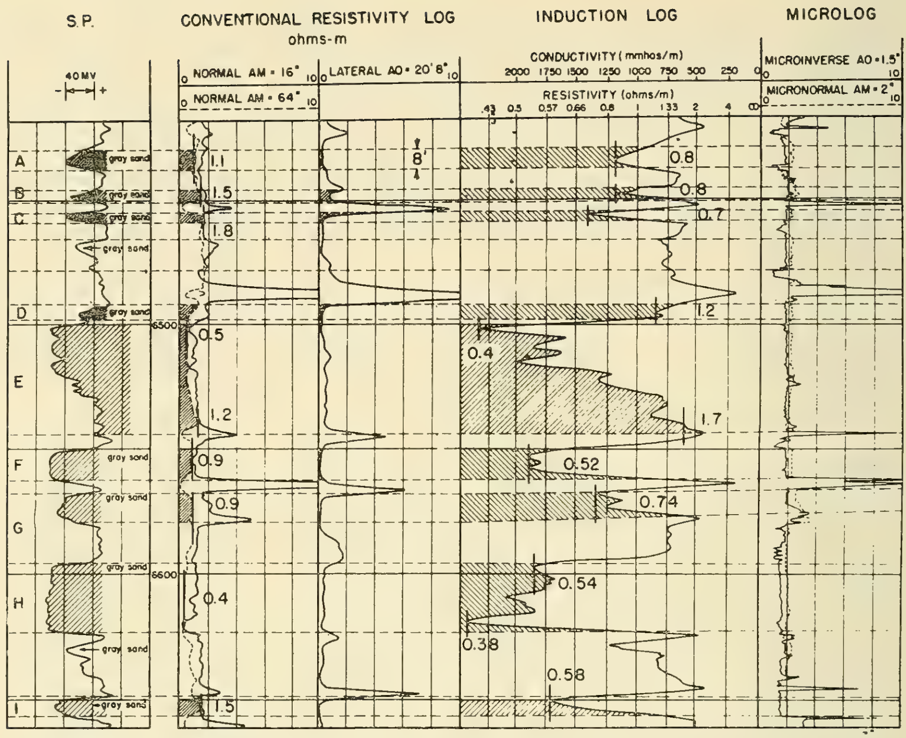


FIGURE 14-15. Conventional log, induction log and microlog in sand-shale series (Gulf Coast).

The reservoirs in this type of formation are very often dirty sands, and the contrast between the resistivities of water-bearing sands and oil-gas-bearing sands is not very great; good producers can be obtained when true resistivities are low. It is, therefore, important for a correct quantitative analysis that the true resistivities can be determined with great accuracy. The above emphasizes that when the beds are thin the necessary accuracy can be obtained with the induction log only.

Figure 14-16 shows the logs recorded opposite sands embedded with comparatively tight formations and shales (Lower Cretaceous-Mississippian). The main difference with the preceding example is that most of the sands are more consolidated and that the proportion of tight material is appreciably greater; this fact is shown clearly by the comparison between the MicroLogs.

Section B, for example, is a 7-foot sand located between appreciably more resistive formations. The long normal accordingly reads 3.7 against 1.7 for the induction log. The lateral shows a steady decrease from the top to the bottom of the bed, as is usual below a thick resistive formation, until a minimum

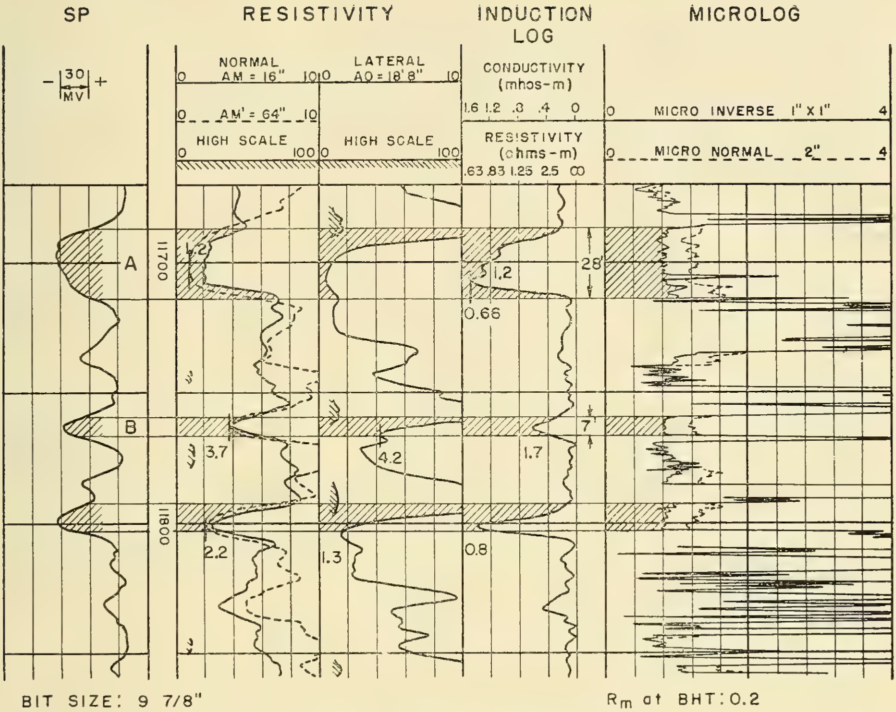


FIGURE 14-16. Example of induction log.

of 4.2 is reached. Similar observations apply to the other sands. The induction log readings are systematically lower than the readings made with the long normal, essentially because of the effect of bed thickness and also of invasion.

The effect of invasion can be discriminated over a thick interval like A (28 feet) where the presence of the adjacent formations has little effect on the normal readings. Here the short normal attains a minimum value of 2 ohms and the long normal 1 ohm; the effect of invasion is the smallest on the induction log, which reads down to 0.66. As for the lateral, the readings are disturbed by two resistive beds immediately above and within section A.

Conclusions

Induction logging seems to be the most proper method for the investigation of true formation resistivities, particularly in thin beds, in wells drilled with comparatively fresh muds.

It is now used more and more extensively in those regions where the reservoir formations have a high or medium porosity. Its combination with the short normal, the SP, the MicroLog, and the microcaliper gives the most complete and accurate record of the formations.

Induction logging will also continue as the proper method for the surveying of empty holes and of holes drilled with oil-base mud, possibly in combination with an additional curve run with scratcher electrodes and with the radioactivity logs.

Laterolog

The Laterolog is a resistivity measuring method wherein the current is forced to flow radially through the formations as a sheet of predetermined thickness, by means of an appropriate electrode arrangement and automatic control system.

With the Laterolog, the measurement involves a portion of ground of limited vertical extent; the measured value is practically unaffected by the mud column.

The main advantages of the Laterolog over the conventional log are the following:

a. It shows sharper discrimination between different beds and more accurate definition of their boundaries.
b. It gives closer approximation to the true resistivity of thin beds, especially in formations drilled with high salinity mud.
c. The Laterolog is useful for the logging of thin beds in formation of low or moderate resistivities where the drilling mud is very saline and for formations of high resistivity where any water-base mud is used.

Principle

There are two types of Laterologs, 7 and 3, corresponding to the number and shape of electrodes. Laterolog 7 uses point electrodes as schematically represented on Figure 14-17. The device comprises one current electrode, A_0, and three pairs of electrodes, M_1 and M_2, M'_1 *and* M'_2, and A_1 and A_2, placed symmetrically with respect to A_0, the pairs being respectively short-circuited. A current of constant and calibrated intensity is sent through electrode A_0. Additional current of the same polarity is fed through the auxiliary power electrodes, A_1 and A_2. The intensity of these currents is automatically and continuously adjusted in such a way that the difference of potential between the short-circuited pairs, M_1M_2 and $M'_1M'_2$, is maintained substantially equal to zero. The potential prevailing at any of these four electrodes is measured.

According to this system, the current emitted from A_0 is prevented from flowing upward past electrodes M_1 and M'_1 or downward past electrodes M and M'. Accordingly, the distance the current travels across the mud is very small; and the mud column has very little influence on the measurements except in deep caving. The current is obliged to flow within an approximately

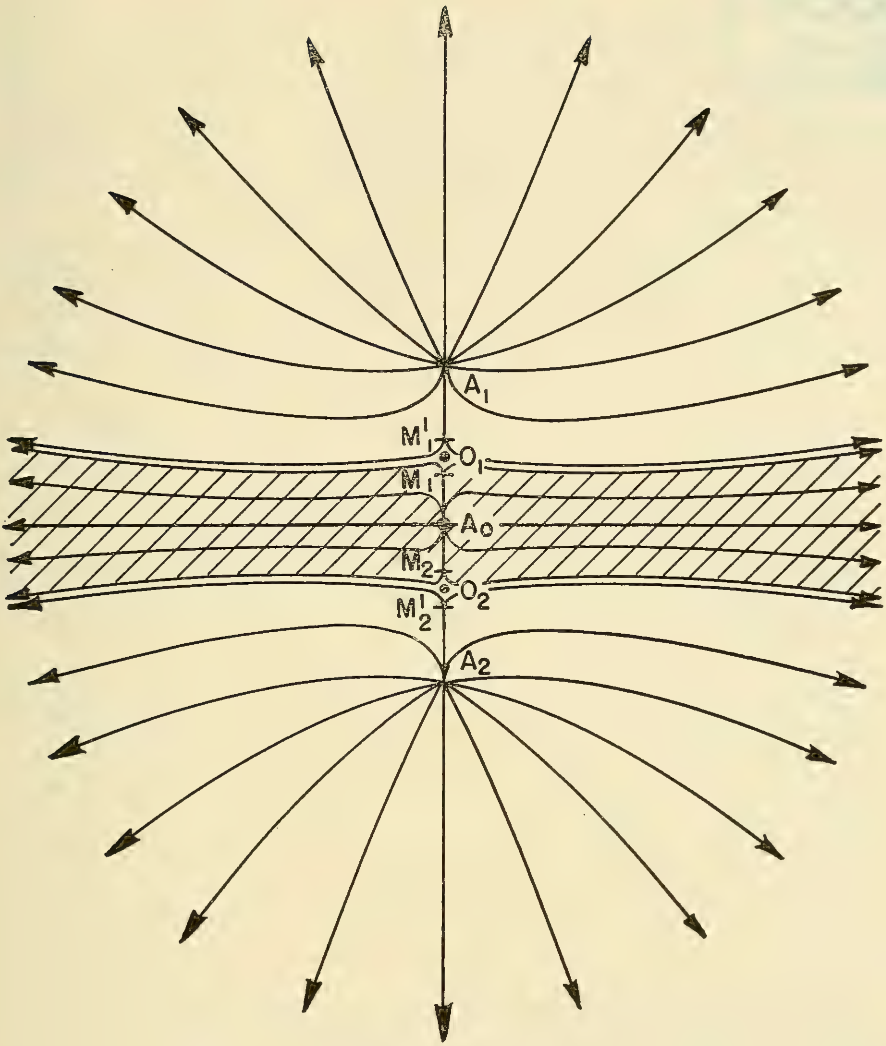


FIGURE 14-17. Current distribution of laterolog device.

horizontal slice of space whose thickness is about equal to the distance separating the midpoint of $M_1M'_1$ from the midpoint of $M_2M'_2$, or 32 inches.

The Laterolog 3 consists of a center-point electrode that emits a constant calibrated current and long elecrodes above and below that are used to achieve focusing somewhat as in the Laterolog 7. A smaller beam width can be obtained, so that this device is useful for studying very thin beds.

Effect of Invaded Zone

In permeable beds, the current used for the measurement has to cross the invaded zone radially before reaching the uncontaminated zone. The apparent resistivity is proportional to a voltage, which includes the ohmic drop of potential across the invaded zone and the ohmic drop of potential across the uncontaminated zone. If the invasion is deep, the effect of the invaded zone on the apparent resistivity may be comparatively important.

Departure curves have been computed for thick beds, which give the value of apparent resistivity read with the Laterolog 7 versus the true resistivity for various depths of invasion and various resistivities of the invaded zone.

It is possible to summarize the computed results into a few simple formulas that enable a quick correction of the readings for invasion effect: namely,

For $D_i = 20''$, $R_a = .2\ R_{xo} + .8\ R_t$ or $R_t = 1.25\ R_a - 0.25\ R_{xo}$

For $D_i = 40''$, $R_a = .4\ R_{xo} + .6\ R_t$ or $R_t = 1.66\ R_a - 0.66\ R_{xo}$

For $D_i = 80''$, $R_a = .6\ R_{xo} + .4\ R_t$ or $R_t = 2.5\ R_a - 1.5\ R_{xo}$

In these formulas, R_{xo} can be given by the MicroLog or the MicroLaterolog. The value of D_i has to be assumed since there is no well-logging tool available at the present time to determine this directly.

Because R_{xo} is a direct function of R_m, the effect of the invaded zone depends directly on the mud resistivity. It is interesting to define what should be the optimum value of R_m so that the invaded zone effect will be small.

To illustrate the discussion, let us take the following numerical values:

$F = 30$, $R_w = 0.05$

$R_o = 1.5$ for 100 percent water saturation

$R_t = 24$ for 25 percent water saturation

Fresh Mud

If one assumes that the mud resistivity is equal to 1, R_{xo} will be approximately equal to 30. With such a mud, the invaded zone will be practically nondisturbing when the formation is oil-bearing, since $R_{xo} = 30$ is close to $R_t = 24$.

For the water-bearing formations, the readings will be equal respectively to 7.2, 12.9, and 18.6, according to the depths of invasion. The apparent resistivities are, therefore, much above the true resistivity ($R_o = 1.5$), even for a moderate diameter of invasion, as $D_i = 2d$. The Laterolog, accordingly, is not able to discriminate oil-bearing from water-bearing beds, even qualitatively, except when invasion is very shallow.

If one assumes now that the mud resistivity is equal to 0.1, R_{xo} is approximately equal to 3.

In oil, the values found for R_a are respectively 19.6, 15.4, and 11.4 against the true value, 24. When the formation is water-bearing, the values of R_a are 1.8, 2.1, and 2.4 against 1.5, the true value. The Laterolog thus reads below the true resistivity for oil-bearing and above for water-bearing beds. The relative errors are very small for shallow invasion and, though appreciable, are still acceptable in deep invasion. At any rate, the qualitative discrimination between oil-bearing and water-bearing beds is quite clear.

It appears from the preceding that conditions favorable to the use of the Laterolog are obtained when the resistivity of the mud is low; the Laterolog, therefore, finds an excellent field of application in those instances where, in contrast, the conventional log is the most adversely affected.

It seems worthwhile mentioning that exceedingly conductive muds have some drawbacks, the most important of which is the reduction of the SP curve to an almost flat line that is thus of no value for the discrimination between shale and permeable beds. Taking into account all the aspects of the interpretation, one can say that the optimum mud resistivity should be selected at about 3 to 5 times the connate-water resistivity.

Effect of Bed Thickness

The Laterolog, because of its focusing system, is better adapted for the investigation of thin beds than the conventional devices. In order to illustrate this point, the Laterolog 7 will be compared to a normal device in a schematic example of a thin bed of high resistivity, non-invaded and bounded by thick formations of low resistivity, with the thickness of the bed being slightly greater than that of the sheet of current (fig. 14-18).

The figure is divided into two parts by a vertical dash-dot line that coincides with the axis of the borehole. A power electrode A is shown on the axis midway between the boundaries of the bed. The distribution of the current emitted from electrode A without any focusing system—a normal device—is represented qualitatively on the left part of the figure. This distribution, corresponding to the use of a focusing system, is shown on the right.

For the device without a focusing system the current lines diverge from A in all directions and are definitely attracted upward and downward by the adjacent formations, more conductive than the bed, so that the resistance offered by the bed to the current is, to a great extent, by-passed. The apparent resistivity read opposite the bed is, therefore, much lower than the true resistivity of the bed. With the Laterolog, all the current lines flow within the boundaries of the bed, at least over a large distance from the borehole, so

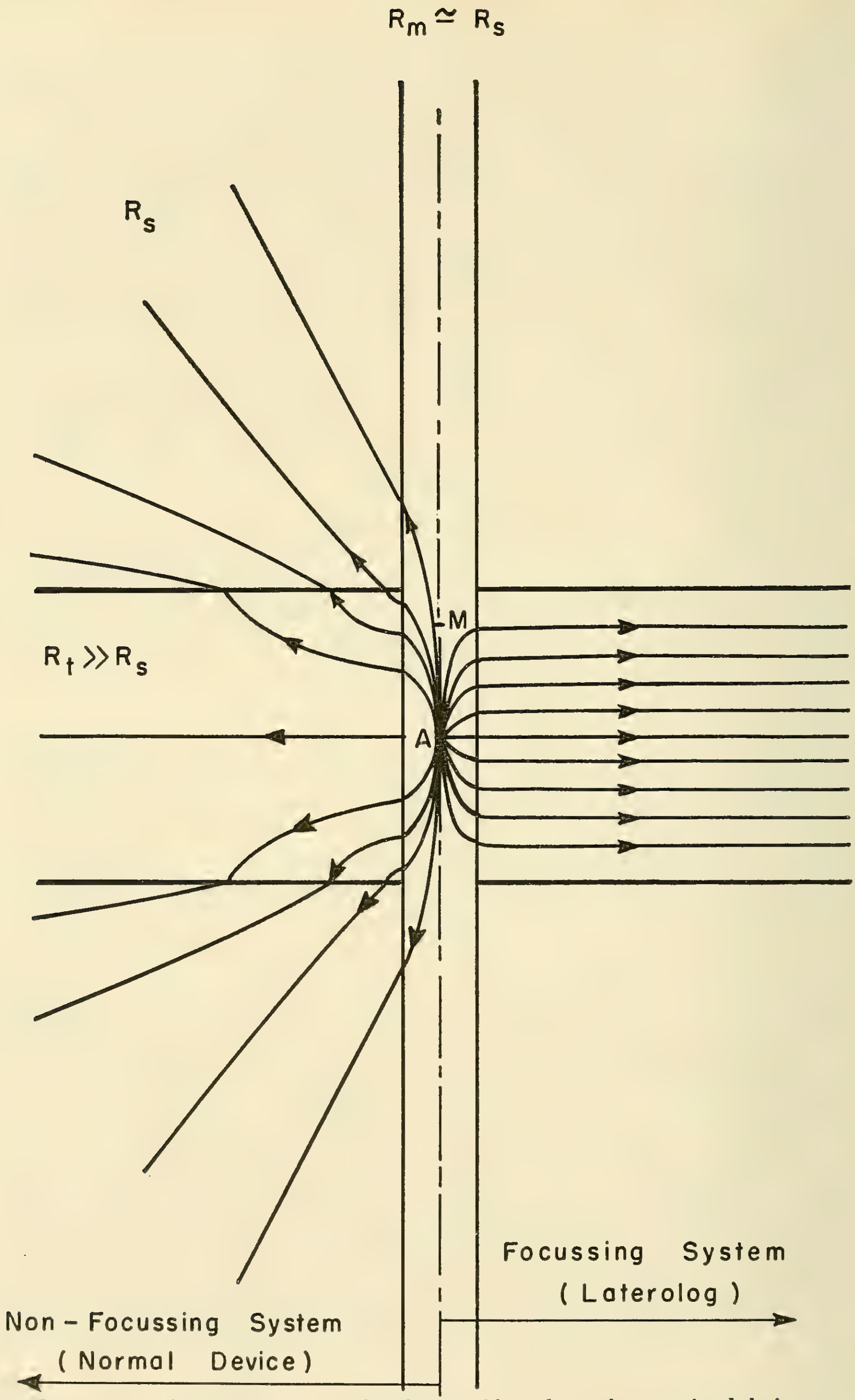


FIGURE 14-18. Comparative current distribution of laterolog and conventional devices.

that the potential at M is directly controlled by the resistivity of the bed. The apparent resistivity then is close to the true resistivity of the bed.

Figure 14-19 shows a typical example of a curve recorded in the laboratory opposite a thin noninvaded bed, more resistive than the adjacent formations, and traversed by a borehole filled with mud of low resistivity.

In this figure the thickness of the bed, e, is equal to five times the hole diameter, d. The spacing of the Laterolog 7 device is $1.5d$. For a usual value of hole diameter, say about 9 inches, these values correspond respectively to a bed thickness slightly less than 4 feet and to a thickness of the current sheet slightly greater than 1 foot. The resistivity of the bed is equal to 100, the resistivity of the mud to 0.1, and the resistivity of the adjacent formations to 3.

The curves recorded with the short normal AM $= 1.75d$ (16″), a long normal AM $= 7d$ (64″), and a lateral device AO $= 25d$ (18′ 8″) are shown on the figure for comparison.

It is seen on the figure that the Laterolog device gives a much sharper indication of the boundaries of the bed than the conventional devices. Moreover, the value of the apparent resistivity read with the Laterolog on the center plane of the bed is equal to 80, against 100; whereas the conventional devices show 4, 5, and 12, respectively.

In hard-rock territories, the porous and permeable sections are most often located between tight formations; in other words, the resistivity of the reservoirs is usually smaller than the resistivity of the adjacent beds. The result of the laboratory tests available for $R_t < R_s$ show that the effect of the adjacent formations can be neglected without too great an error in saturation evaluation if bed thickness is greater than about 4 feet.

Conclusion

The Laterolog gives a sharp record of the sequences of beds, whatever the mud resistivity. It is, therefore, an excellent tool for formation definition and for correlation.

The Laterolog is chiefly appropriate to well logging in hard-rock territories, where it has been accepted as essential for the definition of beds, for correlation, and for reservoir evaluation.

The Laterolog finds its most favorable conditions of applications in wells drilled with high-salinity mud. Under such conditions, it constitutes the basic tool for the investigation of R_t and, hence, of saturation.

In wells drilled with fresh mud, the Laterolog is generally used at the present time as an addition to the conventional logs and the MicroLog. The Laterolog may possibly be used in the future as an auxiliary tool to the induction log.

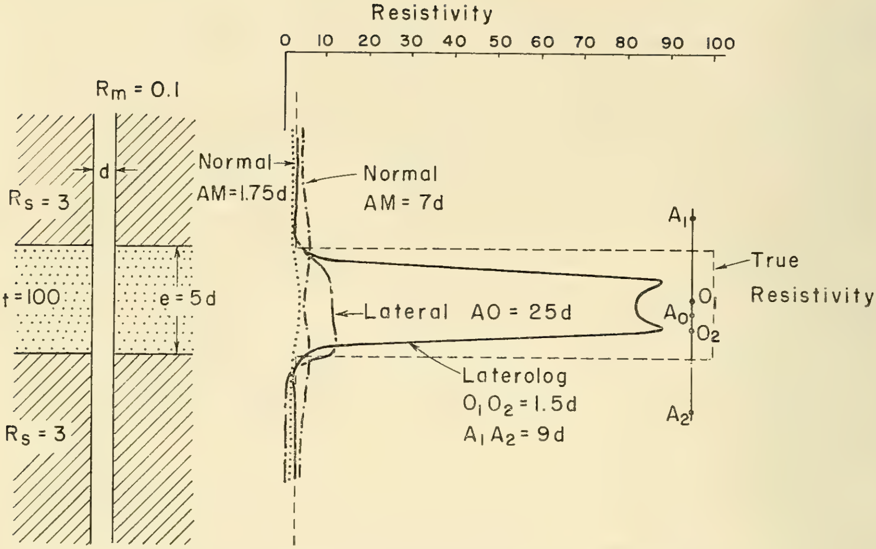


Figure 14-19. Response of laterolog and conventional devices.

MicroLaterolog

It has been said that the MicroLog is not the proper tool for an accurate determination of R_{xo} when the porosity of the formations under study is lower than about 15 percent. The limitation of the MicroLog is due essentially to the by-passing influence of the mud cake on the measuring circuit.

The MicroLaterolog is a microdevice involving a focusing system whereby the effect of the mud cake on the measurement is reduced and even negligible if the mud thickness is small. Under this condition, the MicroLaterolog is adapted to the determination of formation factor and porosity in all types of formations.

Principle

The MicroLaterolog device comprises one center electrode, A_0, of very small size and three circular (ring) electrodes, M_1, M_2, and A_1, each concentric with A_0 and spaced with short gaps (about ½″ to 1″) between successive rings (fig. 14-20). These electrodes are imbedded in an insulating pad which is applied against the wall of the borehole by means of an appropriate spring system similar to the MicroLog.

A current of known and constant intensity is sent through the current electrode, and another current of the same polarity is fed through bucking-current ring, which is automatically adjusted so that the potential difference between measure and monitor electrodes is kept practically equal to zero.

The diameter of the beam increases, first very slowly and then more and more rapidly, with the distance from the wall. Laboratory experiments have shown that that part of the formations which is located beyond a distance of about 3 inches from the wall has little influence on the measurement.

In a porous and permeable formation, the electrode system is separated from the formation by the mud cake. Inasmuch as the current crosses the mud cake in a direction perpendicular to the wall, the distance it has to travel across the mud cake is small in comparison with the length of the path through the formation. Furthermore, the resistivity of the mud cake is usually less than the resistivity of the formation. As a result of these two factors, the influence of the mud cake on the measurement is much reduced and even negligible for all practical purposes if the mud-cake thickness is not too great. It is recalled, for the sake of comparison, that with the MicroLog the mud cake constitutes a path for a part of the current toward the mud colmun and, therefore, generally affects the measurements much more than with the MicroLaterolog, particularly

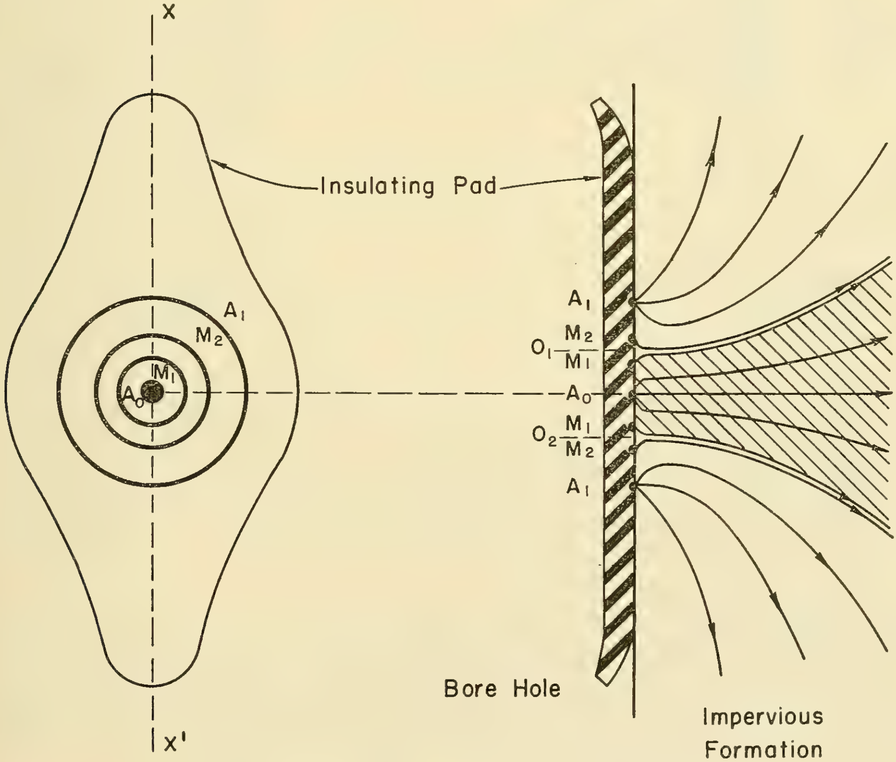


FIGURE 14-20. Schematic drawing of microlaterolog.

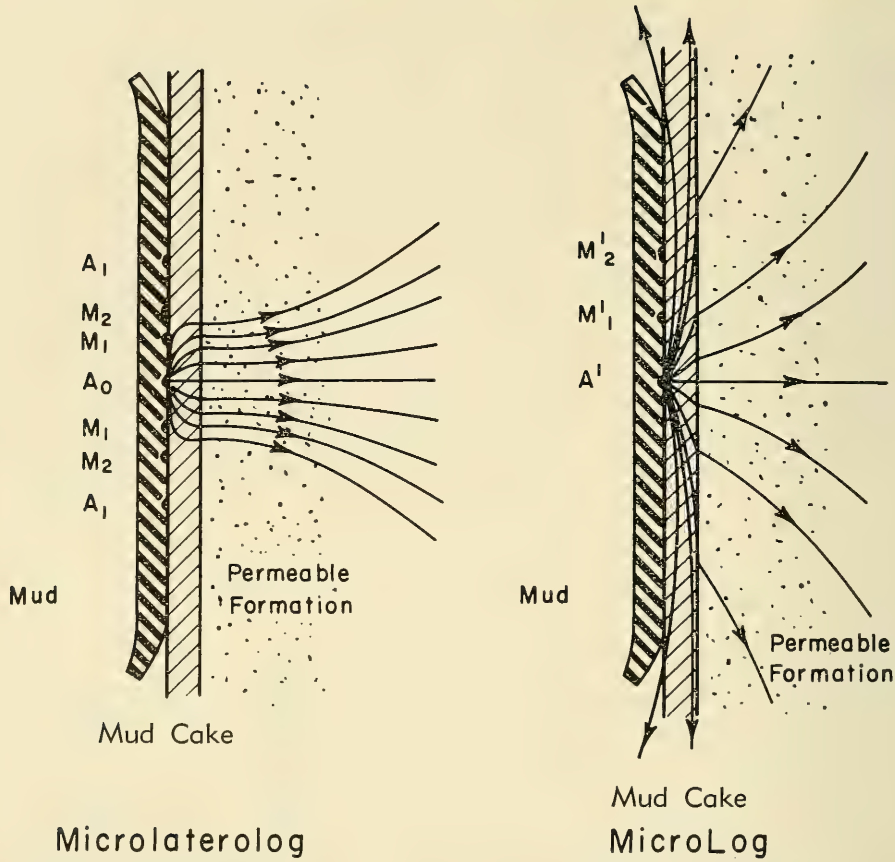


FIGURE 14-21. Comparative current distribution of microlaterolog and microlog.

The equipment used at the present time enables the recording of one single curve run with an electrode system referred to as type A (spacing between successive elecrodes = 9/16″). Laboratory tests and field experience have proved that this equipment gives the measurement of R_{xo} and, hence, of formation factor and porosity, without correction, when the mud cake thickness is not greater than about 3/8 inch.

Interpretation and Applications

Inasmuch as the current beam has a very small diameter (about 2″), the power of resolution of the MicroLaterolog is very high; the recorded curves for formations with low porosity (fig. 14-21). Therefore, when the mud cake is relatively thin, measurements obtained with the MicroLaterolog involve chiefly the flushed zone.

can, therefore, give an accurate and detailed definition of the boundaries for very thin beds.

Tight Formations

Since these formations usually do not cave much, the pad is seated against them; and very high readings are obtained.

Shales

When there is no caving, the pad is applied to the formations. Because of the focusing system, a thin mud film between the pad and the wall has no influence on the measurement which, therefore, is equal to the resistivity of the shale.

In the MicroLog, caving may give similar features on the curves as porous beds. The discrimination of these features is again possible with the help of the SP and the microcaliper curves.

Porous and Permeable Formations

The MicroLaterolog is essentially a tool for the determination of R_{xo}. It seems superfluous to elaborate here on the significance and the use of this factor in the quantitative analysis of the electric logs for the evaluation of porosity and saturation.

Mud-Cake Thickness Less Than 3/8 Inch

The resistivities recorded with the MicroLaterolog give directly the values of R_{xo} without need for correction.

Thin mud cakes are observed in wells drilled with high salinity muds. The MicroLaterolog, accordingly, is one of the components of the so-called salt-mud survey technique, which is used more and more extensively in hard-rock territories where high-salinity muds are used.

Mud-Cake Thickness Greater Than 3/8 Inch

The effect of the mud cake is no longer negligible, and the resistivities recorded with the present type A are generally lower than R_{xo}. Interpretation charts have been established in the laboratory, which make possible the determination of R_{xo} when the mud cake thickness is known.

The equipment for the simultaneous recording of the MicroLaterolog and the MicroLog is still under development. Pending its introduction, the value of the mud-cake thickness as given by a MicroLog run in the same well can be used to correct the single curve MicroLaterolog, at least to a first approximation, by using the interpretation charts mentioned above.

It is sometimes possible to use the indications of the microcaliper for the determination of mud-cake thickness. But such a determination should be made with caution; the difference between the nominal hole diameter, given by the drill bit size, and the actual hole diameter shown by the microcaliper gives the exact mud cake thickness only if the formation under consideration has not caved.

Laboratory investigations and field tests are in progress in order to select more appropriate electrode spacings, whereby the influence of the mud cake on the MicroLaterolog readings could be further reduced.

New Developments

Three paths of future development of the electric log are obviously open and are being vigorously investigated at the present time. Indications are very optimistic that results from these investigations will be available in the near future.

The first of these is the further development of interpretation techniques of the presently available logs. This is a subject of constant study.

The second is the combination of various tools to provide for simultaneous recording. As two or more services are combined, their effectiveness will be increased and their cost decreased.

The third and possibly the most important is the trend toward focused types of logs. Since the borehole, mud-invaded zone, and surrounding beds cause the departure of apparent readings from true readings, focusing to eliminate the effect of these factors will definitely improve the usefulness of the log.

During 1956, an induction-electric log combination that was introduced is being widely used. It is a simultaneous recording of a short normal of 16 inches, an induction log of 40-inch spacing, and an SP curve. This combination is restricted to fresh muds and reads close to true formation resistivity without distortions common to multiple-electrode-spaced logs. The correlation between the new induction-electric log combinations and the old standard electric log presents no problem inasmuch as the short normal and SP curves are common to both. Identification of productive zones is much simpler with this new combination, and it lends itself to quick and easy interpretation.

In the future an induction-Laterolog combination is expected to give a superior log in regions of medium- and high-resistivity formations for both fresh and salty muds.

USES AND INTERPRETATION OF ELECTRIC LOGS

The main applications of electric logging are the following: delineation of formations and determination of their boundaries, investigation of porosity and fluid content, investigations in oil-base mud and empty holes, etc.

Delineation of Formations and Determination of Their Boundaries

The conventional resistivity curves (chiefly the short normal and the SP curve, usually give sufficient data for correlation of unconsolidated and moderately consolidated formations (medium- and high-porosity sands and sandstones and shales). An example of correlation is given in Figure 14-22. The SP curve is fundamental for the delineation of permeable beds. In addition, the MicroLog, run preferably with a microcaliper, is necessary for a more accurate definition of the boundaries, particularly those of thin shale beds and hard streaks interbedded with the permeable sections. The MicroLaterolog may be used instead of the MicroLog. In very salty mud, the SP curve is replaced by the gamma ray curve.

The conventional resistivity curves (normal and lateral) and the SP curve usually delineate large bodies of formations with different average lithological characteristics and make possible good general correlations of hard formations (limestones, dolomites, and highly consolidated sandstones). The curves very often do not give an accurate representation of thin sections with different lithologies. The limestone curve reflects more closely the lithologic variations and helps for correlation. The Laterolog gives a more detailed and accurate record of the formations and makes possible better correlation. The most detailed and accurate record of porous and permeable beds, of tight sections, and of shales is given by the MicroLog or the MicroLaterolog with the help of the SP curve, the microcaliper, and the gamma-ray curve. The radioactivity methods (gamma ray and neutron), although they do not give as much information as the electric methods, are good tools for correlation.

Investigation of Porosity and Fluid Content

Evaluation of Porosity

Unconsolidated and Moderately Consolidated Formations

The determination of porosity from the electric logs is based essentially on the measurement of R_{xo} by MicroLog or the MicroLaterolog, as seen previously. A fair accuracy in the evaluation of porosity (down to porosity values of 15 percent) is obtained with the most recent type of MicroLog equipment.

Another approach, which can be used to check the results of the MicroLog or to replace the MicroLog in case it is not available, consists of taking the formation factor equal to R_o/R_w, R_o being the true resistivity of the formation at a level where it is 100 percent water-bearing. Of course, the extrapolation of the value of F thus determined to the oil-bearing section within the same formation implied that the lithological characteristics are approximately constant, which is not always the case.

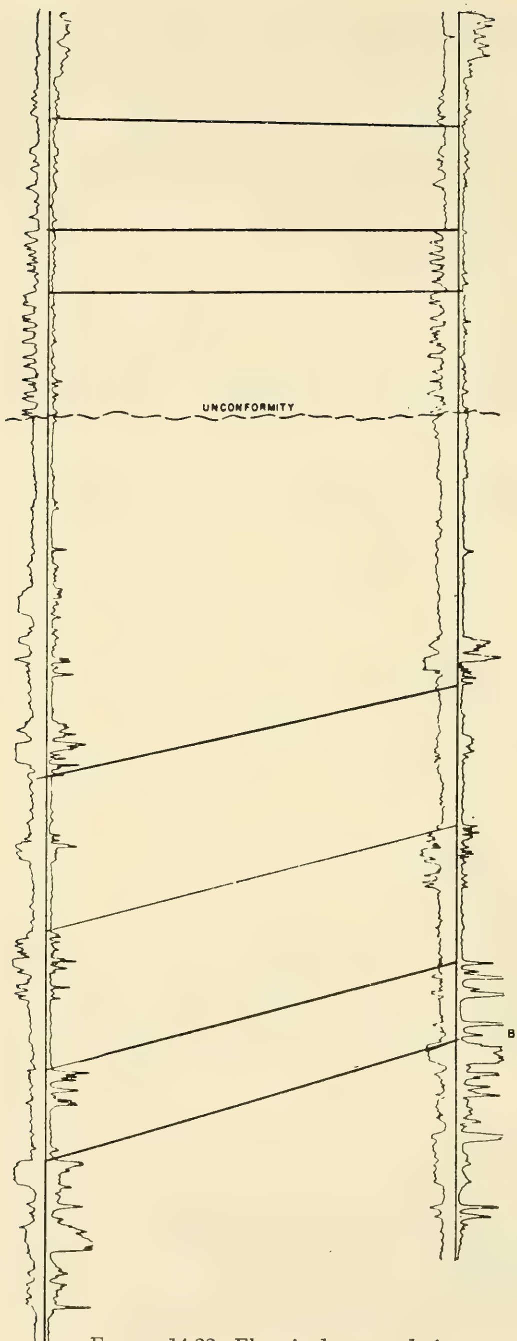


FIGURE 14-22. Electric log correlation.

When the depth of penetration of mud filtrate is very small, as in low-water-loss mud and also in formations having a very high vertical permeability, the value of R_{xo} determined from microresistivity logs does not correspond any more to the flushed zone only, but it may involve a part of the uncontaminated zone. The ratio R_{xo}/R_{mf} (corrected for residual oil saturation, if any) does not, in this instance, represent the formation factor. Also, in the gas-bearing formations, a great amount of gas may be present in the pores near the wall of the hole and may affect the value of R_{xo} to an extent that is difficult to evaluate but that may be very great.

Furthermore, with the present large sample taker, reliable determinations of formation factor and porosity are possible from side wall cores.

Hard Formations

It seems that the basic tools for the determination of porosity should be the MicroLaterolog and the neutron log.

Another approach is based on the value of R_i, the average resistivity of the invaded zone, which can be estimated from the readings of the limestone sonde or the short normal. This procedure, although it does not provide such accurate and detailed results as the one based on R_{xo} (when this latter can apply) has proved valuable in many cases.

Evaluation of Saturation

Unconsolidated Formations

The conventional electric logs may be used for the evaluation of saturation when the beds are not too thin. In thin beds, the induction log is necessary. It can be said that with induction logging a reasonable quantitative interpretation should be possible in most beds at least 5 feet thick. Reliable qualitative results can still be obtained for thinner beds.

Hard Formations

Where wells are drilled with high-salinity mud, the salt-mud survey technique (gamma ray, Laterolog, MicroLaterolog, and/or neutron log) makes possible a detailed investigation of porous and permeable sections. Quantitative results can be obtained with a fair approximation down to a bed thickness of 4 or 5 feet; and, here also, good qualitative analysis is often possible for even smaller bed thicknesses.

The investigation of thin porous and permeable sections is more difficult in this instance because appropriate induction logging and MicroLaterologging tools are not yet standardized.

It is, nevertheless, possible to obtain useful information on the average value of saturation over thick intervals by using the average value of R_t

derived from the lateral and the average value of the formation factor derived from the limestone sonde or the short normal. Such a procedure, which involves several assumptions, has often provided valuable results.

In hard formations permeability is generally low; and, as a result, a resistivity gradient is observed on the logs between the zone of lowest water saturation and the water level. The existence of this gradient is the basis of a method for the delineation of intervals saturated with hydrocarbons.

Investigations in Oil-Base Mud and Empty Holes

The methods applicable in this instance are induction log, resistivity curves with scratcher electrodes, gamma-ray log, neutron log, section-gauge log, and temperature log. All these methods can be applied for the definition of beds and correlation. For reservoir analysis the neutron log provides formation factor and porosity determination, and the induction log gives a record of R_t.

Interpretation of Electric Logs

Standard Technique

As seen under Fundamentals of Electric Logging, the water saturation is $S_w = \sqrt{R_o/R_t}$. If we assume that the true resistivity (R_t) can be obtained from the bed under study, it suffices to get the value of R_o corresponding to the same bed. Such value of R_o can be obtained at the bottom of the section under study or in the same sand in a nearby well. In this instance, the water-sand resistivity can be used effectively as long as both the porosity and the salinity of the formation water are constant throughout the section.

It has also been shown that the resistivity of a water sand is equal to the product of the formation factor F and the formation-water resistivity R_w: $R_o = FR_w$. It is also shown that the formation-resistivity factor is related to porosity values by means of comparatively simple empirical relations.

It is always easy to calculate the value of R_o corresponding to a given formation when one knows the formation factor, F, (or porosity, ϕ) and the water resistivity, R_w. The formation factor can often be obtained with sufficient accuracy with the MicroLog and the MicroLaterolog. The water resistivity can be derived from the SP curve.

Rocky Mountain Method

In formations when $R16'' > 10\ R_m$ ($R16''$ is given by the small normal of 16″ spacing), a method was found to give good interpretation when the small normal reading, the long lateral, and the SP were used. This method is known as the Rocky Mountain Method because it was originated in that region.

From the small normal curve, a value for R_i, the invaded-zone resistivity, is obtained by correcting the small normal for hole effect.

From the lateral curve a value for R_t is deduced.
It can be seen that

$$R_i = \frac{F \times R_z}{S_i^2} \text{ if}$$

a. R_z is the resistivity of the water found in the invaded zone. It is usually made up of mud and connate water mixed in such proportion that $\frac{1}{R_z} = \frac{z}{R_w} + \frac{(1-z)}{R_m}$, with z the percent of connate water in the total mixture

b. S_i is the water saturation in the invaded zone. It has been found by experience that $S_i^2 \approx S_w$, so that we can write $R_i = \frac{F \times R_z}{S_w}$.

Inasmuch as $R_t = \frac{F \times R_w}{S_w^2}$, we obtain $S_w = \frac{R_i/R_t}{R_z/R_w}$.

Since R_z/R_w is dependent only on the mud resistivity and the connate-water resistivity, the denominator is a function of the SP value. The upper part of Figure 14-23 gives a graphical solution of this equation. The SP is entered in ordinate and the ratio R_i/R_t on oblique lines. The intersection gives the abscissa, S_w.

The lower part of the chart permits obtaining the porosity by using the water saturation, S_w, just found; and in the ordinate, the value of R_t/R_w. The intersection falls on or below oblique lines that are graduated into porosity values, according to the Humble Formula.

For a good application of this method, the small spacing signal must be nearly independent of the true resistivity, thus requiring sufficient invasion and flushing. The value given by the long spacing should not be too greatly influenced by the invasion. Such conditions are sometimes difficult to obtain in practice; and, consequently, the results will reflect the actual conditions of application. This method should not be used in salt muds.

Interpretation of Shaly Sands

The obvious characteristic of shaly sand is its lack of character on the electric log. The resistivity curves are reduced by the shale in the sand. In some very shaly oil sands, one sees only a small variation between the resistivity of the sand and that of the surrounding shales. The MicroLog does not show much separation between the curves; actually, in many instances, there is no separation.

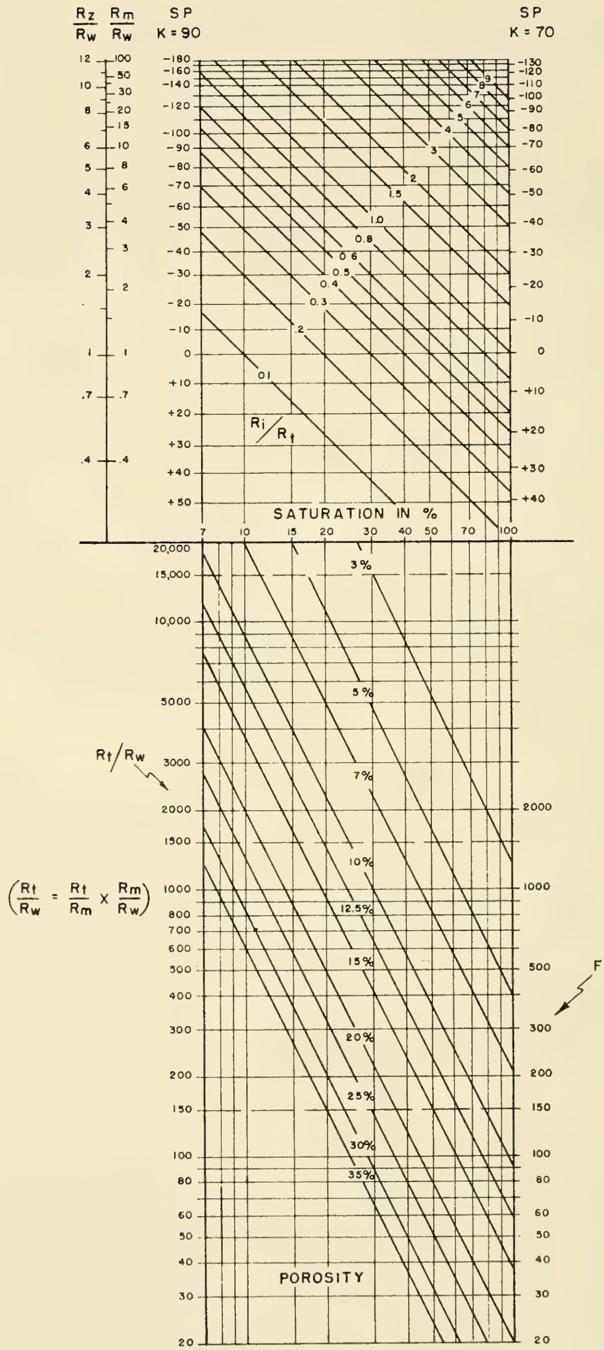


FIGURE 14-23. Rocky Mountain method of electric log interpretation.

The low resistivity of the shale or of the colloids in the sand is responsible for the low resistivity measured. Such low resistivity would seem to infer a very large water saturation even in sands saturated with oil. The resistivity of the flushed zone (R_{xo}) is also affected in the same manner; and, if we used its value to obtain the formation-resistivity factor, a too low value for F results. (Thus, too high porosity is derived.) This is a well-known phenomenon in the laboratory where it is found that the formation resistivity factor in a shaly sand is not a constant, but decreases as the resistivity of the flushing water increases.

It is thus obvious that the standard interpretation technique, if applied, will give too high values of porosity (ϕ) and of water saturation (S_w). In fact, many shaly sands do not exhibit sufficient resistivity to catch the eye of the interpreter unless he remembers that a smaller SP in a given section is sometimes indicative of hydrocarbon saturation in a shaly sand.

A large amount of work has been done in the last few years in order to understand the electric log in shaly sands. For the last two years, a technique has proved quite satisfactory; and we will confine ourselves to the necessary steps to be taken for a good interpretation. This technique applies in sand-shale laminations and also in sands with disseminated colloids.

In a shaly sand it is necessary to use the SP at the level of the formation under study (PSP); and we also need the SSP: i.e., the SP that would have been found had the sand been clean. This can usually be determined by observing the larger SP found near the shaly sand. If this SSP cannot be obtained, the knowledge of R_w, the formation-water resistivity, must be obtained from other sources. Figure 14-24 is used, with the PSP as abscissa and R_{xo}/R_t as ordinate. This gives us the apparent saturation. To find the true saturation, a line is drawn through the origin and the point representing the apparent saturation; and this line is extended until it intercepts the SSP or the corresponding value, R_{mf}/R_w.

It must be remembered that in sand-shale laminations the value of S_w is the water saturation of the sand itself. In disseminated shaly sands, it is the water bound by the quartz grains and does not include the water held by the colloids.

If the SSP is not known and R_w unobtainable, it is not possible to determine the water saturation, S_w. Nevertheless, plotting the ratio R_{xo}/R_t versus PSP on Figure 14-24 will show whether or not the sand falls on the 100 percent water-saturation line. If it falls some distance away from this line, there is a chance for production.

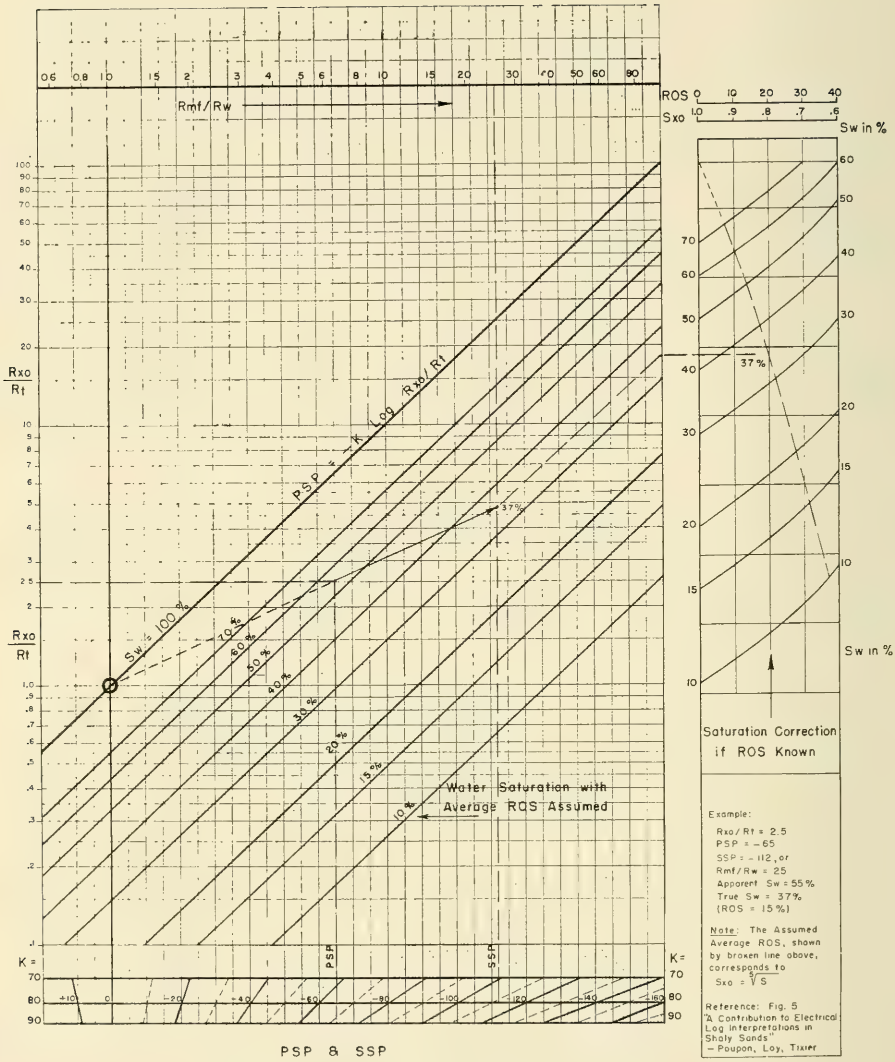


FIGURE 14-24. Saturation determination chart.

Permeability

To date there is no direct logging method for measuring permeability in the hole. It is true that the MicroLog shows the location of the mud cake and thus can point out intervals that have taken mud filtrate and, consequently, have some permeability. This is of particular interest in most hard rocks. In these formations the MicroLog does a spectacular job of showing the presence of mud cake. Nevertheless, such information is only qualitative. In all probability mud cake is formed equally well on formations with a few millidarcies as on sands with several thousand millidarcies.

A method of evaluating the permeability quantitatively from the study of resistivity gradients was offered in 1949. Observations often show that, when a borehole has traversed a reservoir rock that is water saturated at the bottom and oil bearing at the top, the resistivity shows a corresponding increase from bottom to top. In a formation of low permeability, such as consolidated sandstone, it can be further observed that the average trend of the resistivity curve in the transition zone from the water table up to the zone of maximum oil saturation, is practically a straight line. This study shows that the value of the basic gradient (i.e., the resistivity gradient divided by the resistivity at the water level) provides a means for determining the value of the average permeability when the in-place densities of both the hydrocarbons and the connate water are known.

In 1950 some theoretical studies were pursued on the matter of permeability with the conclusion that a permeability range should be obtained without much difficulty if values of porosity and irreducible water saturation are correctly obtained from logs. It was shown that the permeability could be given by a general formula

$K^{1/2} = c \frac{\phi}{S_w}$, with K the permeability in millidarcies, c a factor, ϕ the porosity, and S_w the irreducible water saturation. The coefficient c seems to vary with the square of the porosity, and the general formula becomes

$K^{1/2} = 250 \frac{\phi^3}{S}$. Figure 14-25 shows this relation graphically.

This simple solution is in general all that is necessary to give a working range of permeability, which assists in evaluating the production ability of a given formation. Great accuracy in determining permeability is not indispensable if only because, at the time of production, the permeability can be greatly altered by the type of mud used or by techniques such as acidizing, shooting, and hydraulic fracturing.

Consequently, although there is no way of measuring the permeability directly, in many instances a good idea of the average value of permeability can be inferred with sufficient accuracy to permit a correct reservoir evaluation from the logging techniques.

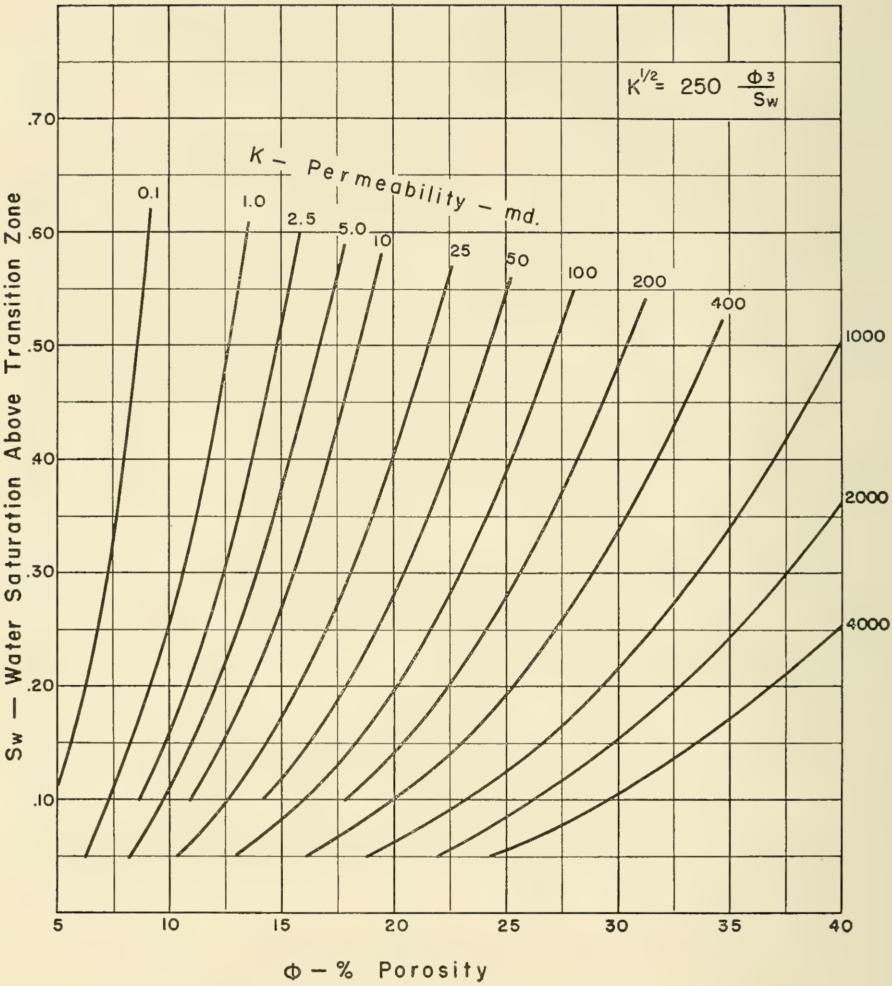


FIGURE 14-25. Permeability in oil sands.

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Chapter 15 RADIOACTIVITY WELL LOGGING

Gilbert Swift
and
Arthur Youmans

Radioactivity well logging makes use of naturally occurring and induced nuclear radiations to obtain useful information regarding the formations penetrated by the borehole. Various types of radioactivity curves are now available commercially, and additional new curves are being offered experimentally. Those which have received most wide-spread acceptance and appear to be of the greatest utility include primarily the gamma-ray and neutron curves, the Densilog, and the input-profile tracer log.

GAMMA-RAY AND NEUTRON LOGGING

The gamma-ray curve is obtained by passing a gamma-ray detector along the well, while continuously recording its indications in correlation with depth. The resulting graph shows the relative concentration of natural gamma ray emitting radioactive elements in the strata traversed. With few exceptions all rocks contain small but measurable amounts of these elements, and in most cases a detectable increase or decrease of radioactive intensity

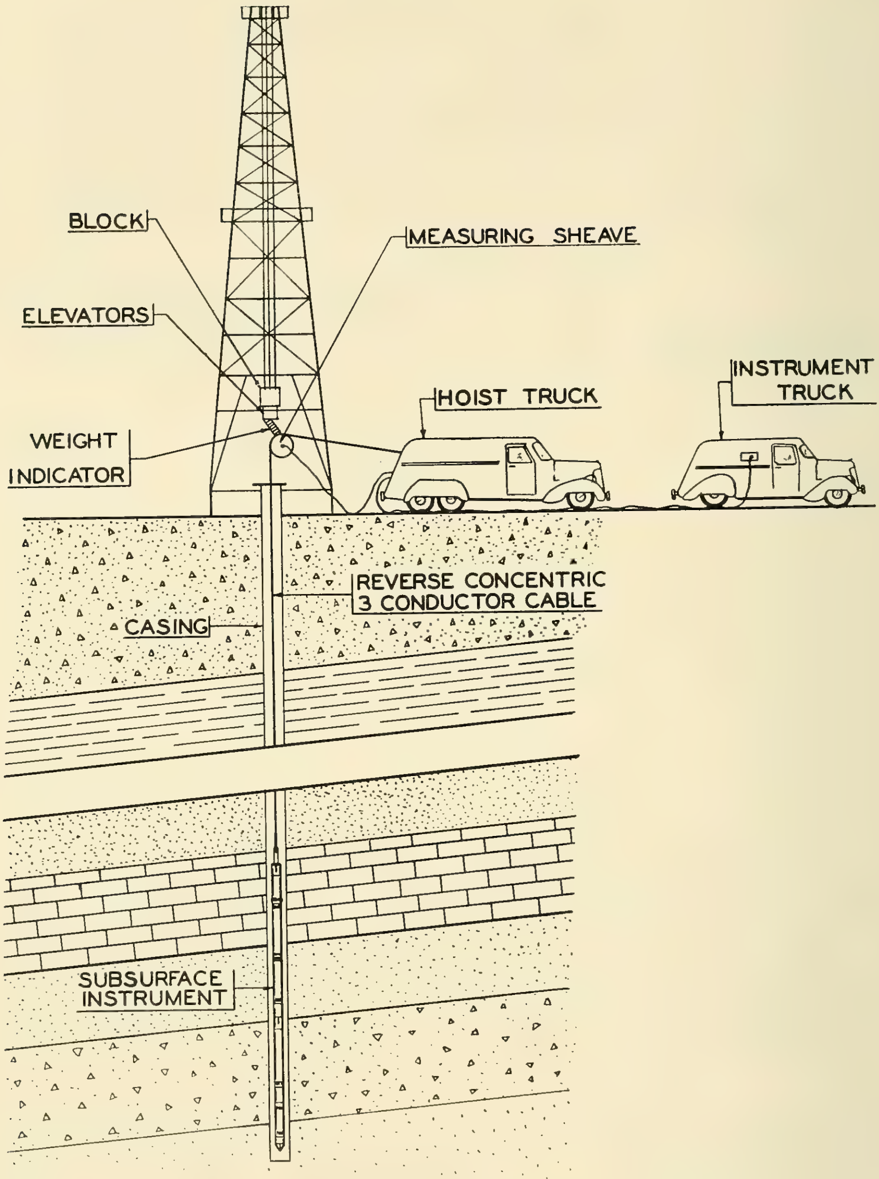

FIGURE 15-1. Radioactivity logging set-up.

occurs at each formation boundary. Generally the sandstones and limestones, which constitute possible reservoir rocks for the accumulation of petroleum, are low in radioactivity, whereas the shales, clays, and siltstones have appreciably higher concentration of radioactive elements. The gamma-ray curve is thus directly applicable to correlation and identification of the strata. By virtue of the penetrating power of gamma rays, which are similar to X-rays and can pass through steel, cement, and borehole fluids, the gamma-ray curve may be obtained in wells which are lined with cement and casing as well as in open holes. Likewise, the gamma-ray curve is obtainable regardless of the type or condition of the borehole fluid. These important properties permit gamma-ray logging to be conducted with equal success in old or new wells and under conditions which may render other logging processes inoperative.

The importance of obtaining, through casing, information relating to the fluid content of the rocks led to the development of neutron logging. A neutron curve is obtained by moving along the well a source which emits energetic neutrons, together with a radiation detector spaced a fixed distance from the source. The detector may be either one which responds to gamma radiation, in which case the method can be properly described as a neutron-gamma process, or one which is sensitive to neutrons. In the latter instance, the method comprises neutron bombardment and neutron detection; hence, it is called a neutron-neutron (n-n) process. In either instance, the results are nearly identical; both types of neutron curve are influenced principally by the amount of hydrogen present in the vicinity of the apparatus, which, in turn, is related to the fluid content of the rocks. The penetrating ability of the radiations employed in neutron logging is such that satisfactory logs can be obtained through several thicknesses of casing. The neutron curve is thus a natural companion to the gamma-ray curve, and the majority of radioactivity logs consist of these two curves. The gamma-ray and neutron curves are generally obtained simultaneously during a single traverse of the well by means of dual logging equipment. Information from the radiation detectors in the subsurface instrument is telemetered to the surface via the logging cable. The log is recorded during the upward traverse of the well to insure that the entire length of the hoisting cable is under tension in order to obtain reliable depth measurements. Logging speeds of 20 to 50 feet per minute are commonly employed.

In cased wells it is customary to record the position of each casing joint on the radioactivity log by means of a magnetic casing-collar locator incorporated in the logging instrument. These indications provide a series of depth markers from which any chosen formation may later be located without depending upon the precise measurement of a great length of cable. Later operations such as gun perforating may thus be performed accurately by locating the nearest casing joint and then raising or lowering the tools a few feet to the desired position.

The photon curve is a log made with an instrument similar to or identical with a neutron logging instrument, except that the neutron source of the latter is replaced by a gamma-ray source. Such a curve is sometimes run to aid in the interpretation of a neutron log when borehole conditions are unknown and a caliper log cannot be run—for example, in a cased hole.

The conventional radioactivity log, consisting of a gamma-ray curve together with a neutron curve, is widely used as a source of information concerning numerous properties or characteristics of the strata or of the well. Most of these properties are related only indirectly to the recorded radiation intensities. The user must therefore combine the pertinent data from the radioactivity log with other available information in order to obtain answers to each of his questions concering the well or the rocks. In this way many questions about the strata, such as the following, can be answered:

What is the depth and thickness of a particular formation?

What type of rock is situated at a given depth?

How great is its porosity or fluid content?

How much shale does it contain?

Does it contain gas?

Questions about the well, such as the following, can be answered:

At what depth is the fluid level?

Where is the casing seat?

Is there a liner present, and, if so, where is its top?

Direct and complete answers to most of such questions require the interpreter to have a working knowledge of the typical responses of the gamma-ray and neutron curves in the formations of his locality and to be familiar with the effects of borehole conditions on the radioactivity log. Adding to this knowledge other specific facts concerning the well and the rocks enables him to identify the stratigraphy and deduce the information from the indications recorded on the log.

Typically, the well conditions remain uniform for hundreds or thousands of feet at a time; and the log responses throughout these sections, therefore, represent variations in the character of the rock materials. With relatively few exceptions, similar rocks all over the world produce similar responses on the radioactivity log. Thus a particular formation can be identified from the log with reasonable certainty. Clean limestones and sandstones nearly always

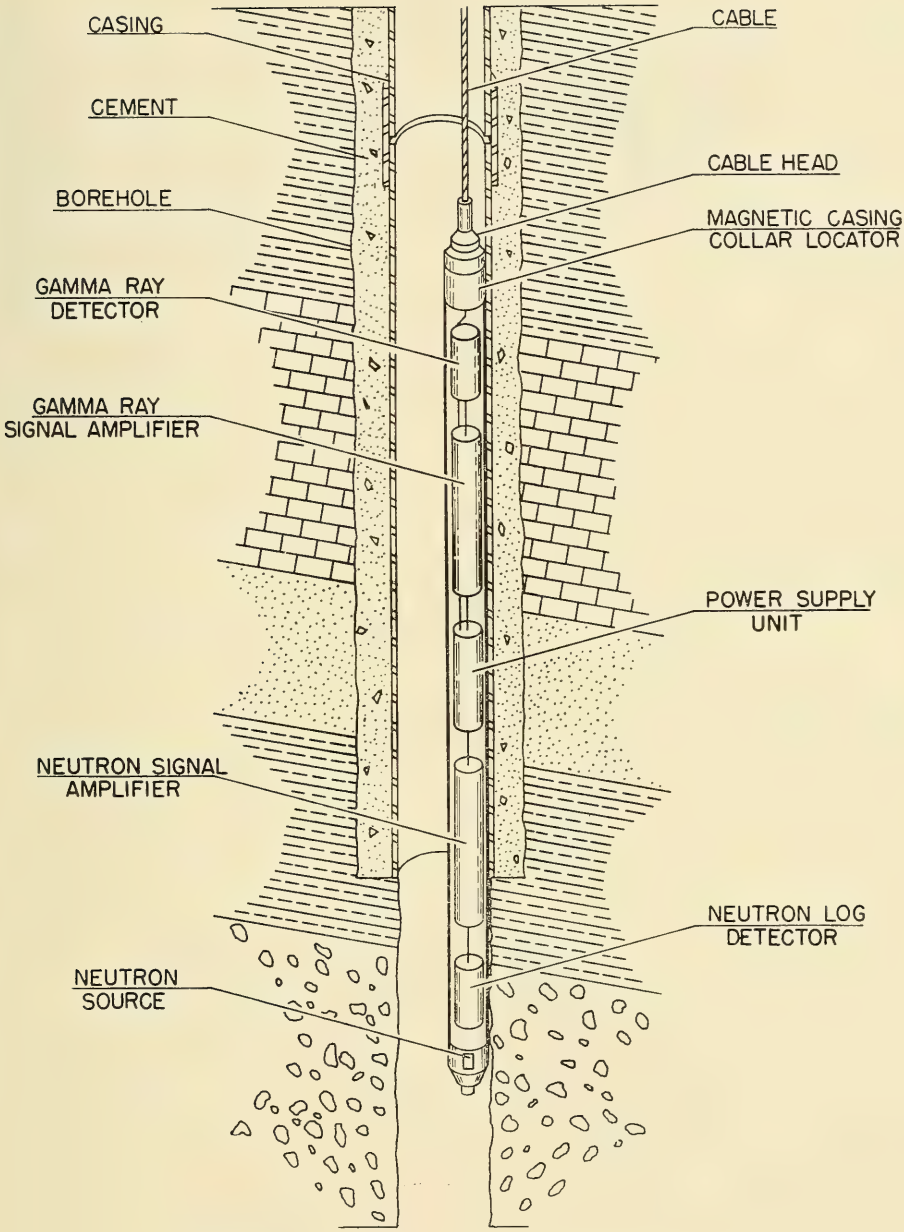

FIGURE 15-2. Gamma-ray and neutron logging instrument.

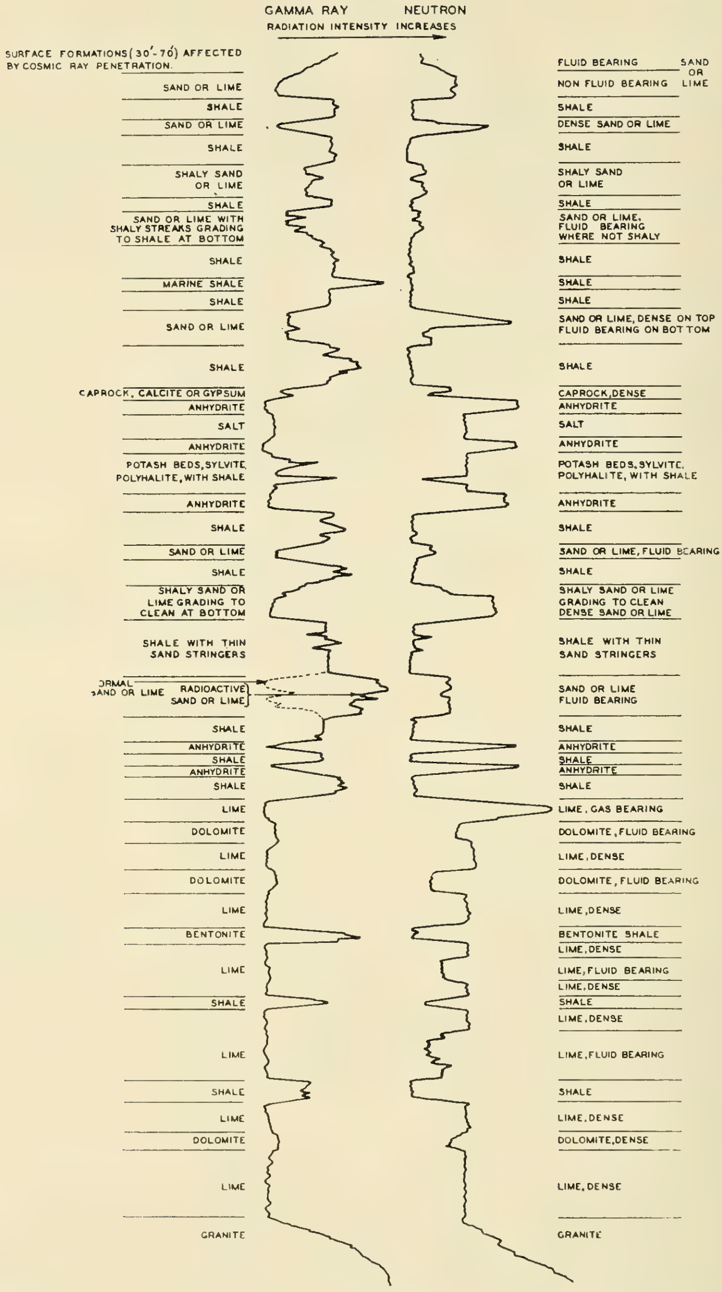

FIGURE 15-3. Typical radioactivity log responses.

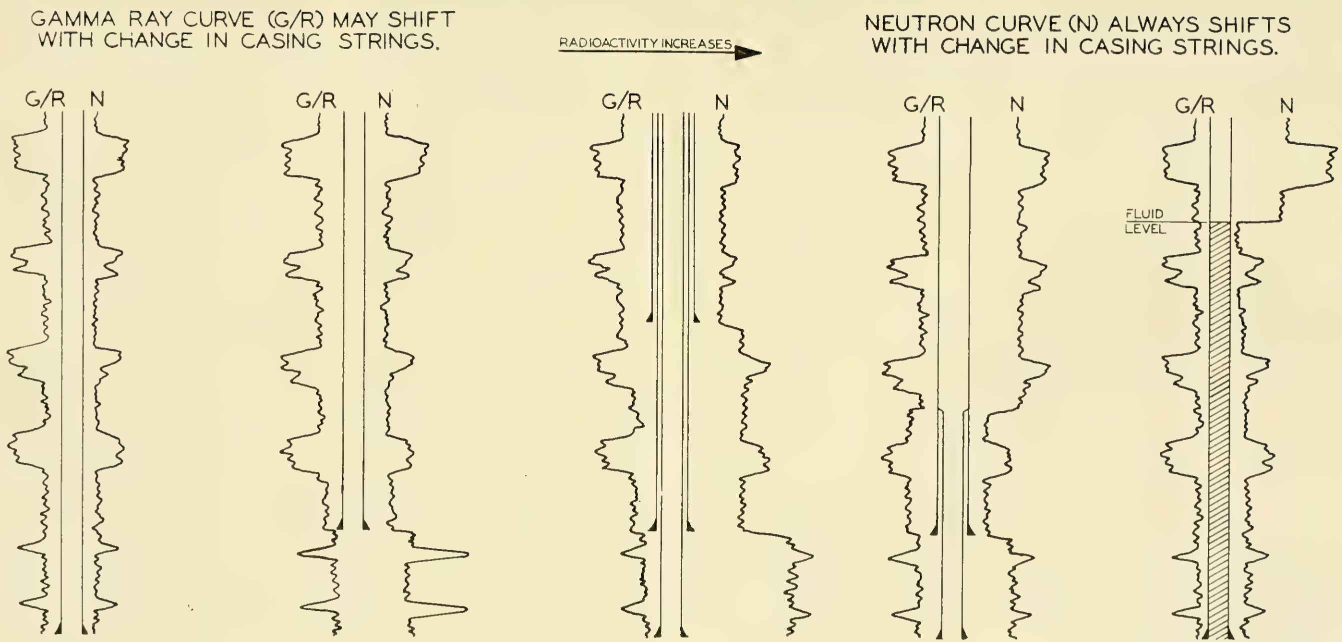

FIGURE 15-4. Effect of physical borehole conditions on gamma ray and neutron curves.

provide the lowest gamma-ray intensities. Halite (salt) is similar, but other geologic knowledge usually permits salt zones to be differentiated from sandstone or limestone. Silty or shaly limestones or sandstones are generally higher in natural radioactivity. Shale almost always records as variable but high in gamma-ray activity. On the neutron curve, dense dry zones and gas-bearing zones provide the highest intensities, whereas shales record at the lowest intensity. Liquid-bearing porous zones are intermediate; the greater the hydrogen content, the lower the response on the neutron curve. However, since shale contains much hydrogen and is thus similar to oil or water in diminishing the neutron curve intensity, the gamma-ray curve or other data must be applied to determine whether producible liquid or shaliness is responsible for a particular neutron-curve response. Increases of radiation intensity are universally recorded as deflections toward the right; thus low intensities correspond to leftward positions of the curve, and high intensities correspond to rightward positions.

Figure 15-3 is representative of the behavior of the gamma-ray and neutron curves throughout the world in responding to variations in rock properties. Typical responses of the gamma-ray and neutron curves to variations of hole diameter, casing thickness, cement, borehole fluid, and other physical conditions pertaining to the well are shown in Figure 15-4.

In contrast to the gamma-ray curve, which is affected only slightly, the neutron curve is greatly influenced by borehole conditions. Not only can variations of the borehole properties be detected and identified on the neutron curve, but they must be identified and taken into account in order to interpret properly the influence of the formations. Thus the heading of the log, which contains a record of the well diameter, the casing, and the borehole fluid, should be studied before attempting to interpret the radioactivity curves. Upon determining that no borehole change occurs within the zone of interest, or if this is not the case, upon locating and recognizing the effect of this change on the log, the user may proceed toward interpreting the curve responses in terms of formation properties.

IDENTIFICATION OF FORMATIONS

Depending upon the particular problem at hand, one or both of the radioactivity curves may provide the basic information required to identify a particular rock. However, even though one curve may allow the identification to be made with reasonable certainty, the other curve supplements and confirms the conclusions. Some common identification problems are listed below with an indication showing whether the gamma-ray curve, the neutron curve, or a combination of the two supplies the basic information.

Problem	Primary Curve	Typical Response
Identification of possible producing zones (sandstones and limestones)	Gamma-ray	Low
Identification of shales	Combination	Gamma-ray — high Neutron — minimum
Identification of liquid-bearing (porous) zones within known producing formations	Neutron	Medium to low
Identification of potash beds, uranium or other highly radioactive zones	Gamma-ray	High or exceptionally high.
Identification of suitable horizons for correlation	Either	Contrasting with surrounding strata
Identification of gas-filled porous zones	Combination	Gamma-ray — low Neutron — extremely high

By following these rules and referring to the typical responses shown in Figure 15-3, or other locally established typical responses, one may use the radioactivity log to identify a wide variety of formations.

CORRELATION

Radioactivity logs respond similarly from well to well and are, therefore, useful in establishing subsurface maps and cross sections from which the depth and thickness of various formations can be traced across a field, or, in many instances, for hundreds of miles. By virtue of the considerable similarity of appearance between radioactivity logs and electric logs, correlations between these two types of logs are ordinarily established with ease. Similarly, the correlation between radioactivity logs and core logs is usually quite apparent. Thus the radioactivity log can be applied to detect and resolve depth discrepancies which may be present in the other data.

DETERMINING FORMATION CHARACTERISTICS

Questions regarding the condition or composition of the rocks; their porosity; their content of oil, water, and gas; and their shale or silt content cannot ordinarily be answered directly from the radioactivity log alone. However, since the gamma-ray and neutron curve responses frequently remain consistent over wide areas, it is often possible to apply with considerable accuracy the knowledge gained from logging one or more wells in which the formation properties are known. In this manner liquid-filled porosity can be determined quantitatively and other formation characteristics, such as shale content or uranium content, can be estimated. To determine porosities from the neutron curve, one first establishes a relationship for the particular field by comparing the core-analysis data with the neutron log of a representative well. In general, the neutron-curve response diminishes in an approximately logarithmic manner as the porosity increases. As illustrated in Figure 15-5, points are plotted on semilogarithmic graph paper, core porosities along the logarithmic axis, and neutron curve deflections along the linear axis. The best straight line then is fitted to the points. Porosities in other similar nearby wells are then read from this graph according to the neutron-curve deflections recorded therein. This method is particularly effective in clean (nonshaly) limestone reservoirs.

In the absence of reliable core data, it is still possible in many instances to estimate porosities from the radioactivity log. Familiarity with local conditions often makes it possible to state with assurance that the porosity of a particular shale-free layer is less than 1 or 2 percent and that the porosity required to diminish the neutron-curve response to the intensity observed in shale is, say, 40 percent. In this way two points are obtained between which a logarithmic scale of porosities may be marked off.

Shale and uranium content may be estimated from the gamma-ray curve by comparing (on a linear basis) its response in the zone of interest with the response obtained in a known shale or a zone of known uranium content. For example, a response one fifth as great as that of a nearby shale may be taken as indicative of 20-percent shale content.

In many instances a strict quantitative relationship has been found to hold between the gamma-ray log deflection and permeability within a particular formation because of the fact that the shale content, which is related to the permeability of the rock, is indicated by the curve. In other instances this indication of the degree of shaliness appears to correlate better with formation porosity than with permeability.

APPLICATIONS OF RADIOACTIVITY LOGGING

Radioactivity logs are run most frequently at the time of completing the well, either just before or just after setting casing. At this time the log is employed to determine the depth and thickness of the various strata, to identify them, and to correlate their depths from well to well in order to establish their structural position. Other data which the radioactivity log may be called upon to provide at this stage include: position of zones of maximum porosity and fluid content, depth of the gas-oil contact, position of the fluid

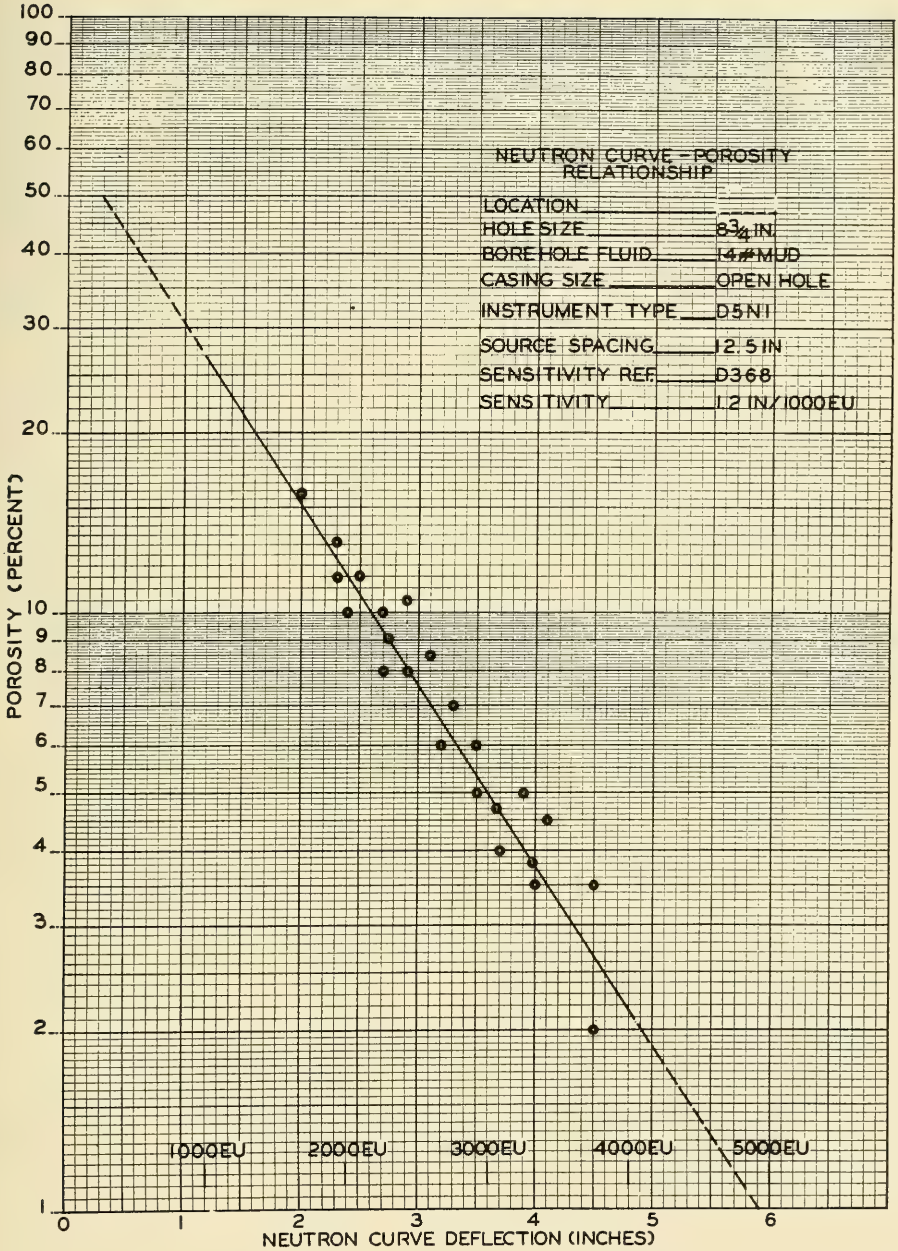

FIGURE 15-5. Neutron curve-porosity relationship.

level, and the casing seat or seats. This data then is utilized in determining whether and where the well is likely to produce, where to make drill-stem tests, where to apply acid or fracture treatment, where to set casing, and where to perforate.

Whether or not the well has been newly drilled, a radioactivity log accompanies almost every perforating operation in order to determine the exact position of the zone which it is intended to perforate. This requires a logging process that responds to formation properties through casing. Further assistance is provided by casing-collar locators on the logging instrument and on the perforating tool. These locators permit the formation depth to be determined with respect to the nearest casing joint and then allow the perforating tool to be similarly positioned.

Gamma-ray and neutron logs are also widely applied in older wells, particularly where well records or earlier logs are incomplete or suspected of being inaccurate. By virtue of the ability of the radioactivity logging processes to operate through casing and independently of the type of fluid in the well, they can be applied under a wide variety of circumstances under which all other logging methods are inoperative. Thus, in older wells, upper productive zones can often be found when the original production has become depleted. Also, reliable data concerning the location of casing seats and liners can be obtained when other records are suspected of being inaccurate.

DENSITY LOGGING

The Densilog was developed to meet the need for a device capable of measuring the density of subsurface formations and to aid in the interpretation of surface gravity surveys. A more important application for the device was found to be the measurement of formation porosity in many types of reservoir rocks. This measurement is possible because most of the common types of rocks have almost the same grain density. Bulk density varies from rock to rock and from point to point in a particular formation, mainly on account of differences in porosity. Thus a quantitative measurement of density amounts to a quantitative determination of porosity, except for rock that has a peculiar chemical constituency. This type of porosity determination is a valuable supplement to the neutron log. Particularly in shaly or cemented sands and in porosities greater than perhaps 15 percent, quantitative interpretation is least accurate for the neutron log and may be satisfactory for the Densilog.

To an even greater extent than the neutron log, the Densilog is sensitive to borehole diameter and fluid consistency. It is also extremely sensitive to the position and orientation of the instrument with respect to the borehole wall. To maintain constant sensitivity to formation density, the instrument is provided with a bow-spring backbone that is designed to hold the sensing

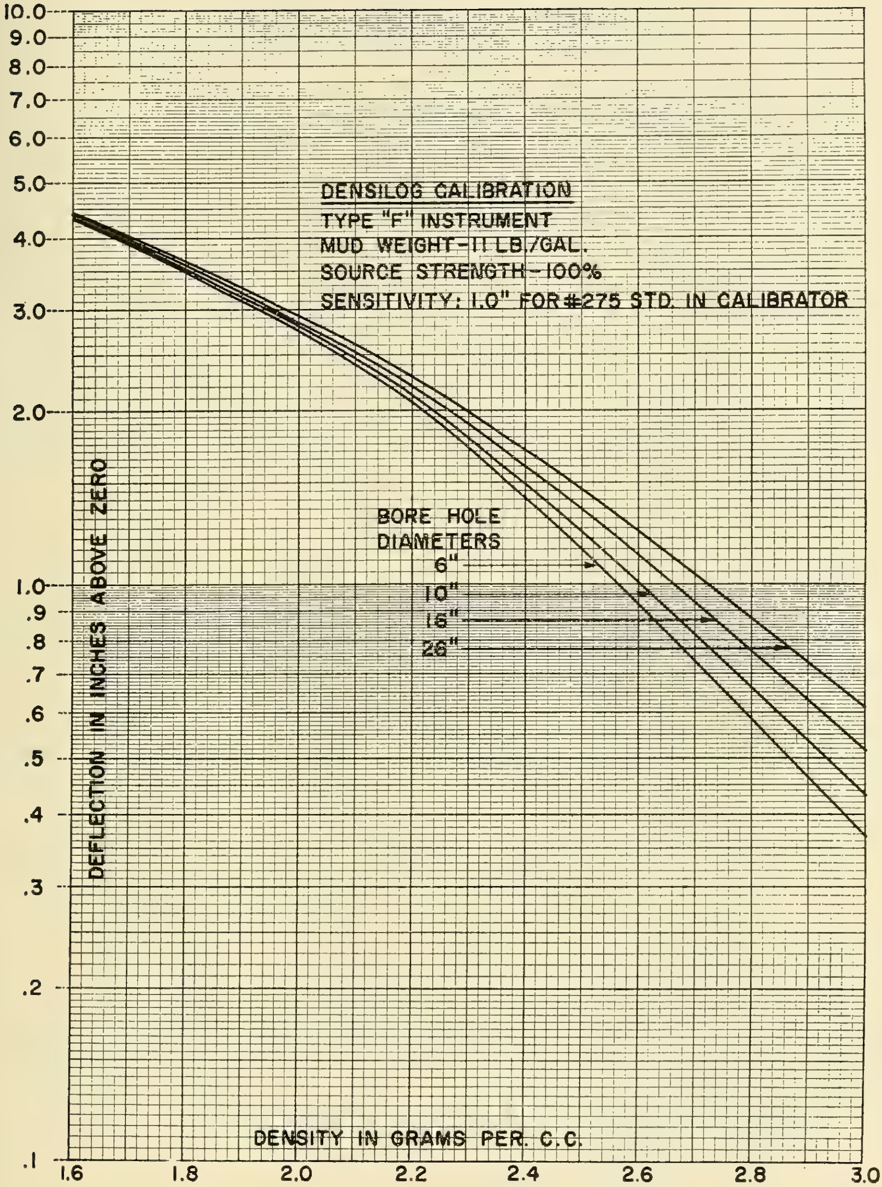

FIGURE 15-6. Densilog calibration curves.

apparatus in contact with the rock face. When the borehole is smooth and true to gauge, precise measurement of formation density can be made. When the borehole diameter varies, a caliper log must be run to facilitate corrections in the measurement. Figure 15-6 shows a family of curves indicating the extent to which the measurement is affected by borehole diameter changes. More serious are the effects on the log that result from abrupt variations in borehole wall condition such as caving. In such instances the bow-spring may be unable to maintain the device in contact with the rock over the sensitive length of the instrument. Under such circumstances the device tends to measure the density of the borehole fluid, and the log is of no value for quantitative interpretation.

Although the Densilog in favorable instances will indicate lithologic changes behind casing, it is primarily useful only in uncased holes. In some areas it has been found to be the best means for stratigraphic correlation and identification of certain formations that contrast poorly with surrounding formations on other logs.

APPLICATIONS INVOLVING RADIOACTIVE TRACERS The gamma-ray curve is useful in observing the position or movement of substances containing small amounts of radioactive tracer material that have been introduced into the well,. Generally a base log is run prior to the introduction of the tracer material in order to distinguish between it and the naturally occurring radioactivity. A comparison of the subsequent gamma-ray curves with the first reveals the distribution of the tracer along the well. Some of the common uses of radioactive tracers in connection with well logging are the following:

1. Determining the distribution of cement in well completions or squeeze-cementing operations. This is done in order to locate the top of the cement or to show which zones have received relatively more or less cement.
2. Determining the relative permeability of producing zones or zones selected for water or gas injection in secondary recovery operations.
3. Studying the flow of fluid from one well to another as in waterflooding gas repressuring.
4. Finding casing leaks or zones of lost circulation.
5. Locating zones opened up by fracturing or acidizing.

The sensitivity of the gamma-ray logging apparatus is such that very small quantities of radioactive tracer materials can be easily detected. Natural and artificially produced gamma-ray emitting isotopes, having long or short half life, and possessing a wide variety of chemical properties, are available. The selection of a particular tracer element and of the physical and chemical form best suited for use depends upon a number of factors pertaining to the individual application. In some applications, as for example in determining permeability, it is important that the radioactive material adhere at the point of entry of the carrier fluid, whereas in other applications the tracer element must remain with the injected fluid. In determining permeability, the radioactive material is attached to particles of resin, just sufficiently large to prevent their entry into the porous rock. In other instances, the tracer may be applied in the form of a highly soluble salt.

CURRENT DEVELOPMENTS Radioactivity logging techniques appear to offer the only feasible means of making quantitative measurements of formation properties after a well is cased. Even in uncased holes it is believed by many experts that nuclear logs offer the best prospect of determining certain rock and fluid characteristics. This is particularly true in many special cases such as air-drilled wells or wells drilled with oil-base mud where one or another of the other logging techniques may not work successfully.

For this reason research and development in this field has received much emphasis in recent years. As a consequence, there has been rapid advancement in the quality and diversification of instruments available commercially. One example is the development of logging instruments for use through tubing in permanent-type well completions. Simultaneous gamma-ray and neutron logging instruments now in service have an outside diameter of only 1⅜ inches. Instruments having a larger diameter, typically 3⅝ inches, have been improved in sensitivity, stability, and reliability. As a consequence, the quantitative interpretation of radioactivity logs has become more accurate and more widespread in application.

Logging instruments have been designed to use many of the techniques of modern nuclear physics. Neutron sources for logging instruments have been built that use a high-voltage ion accelerator to produce artificially neutrons of energy higher than those emitted by conventional capsuled neutron sources. Much research has been conducted on the spectral characteristics of the radiation detected in neutron and gamma-ray logging. Commercial application of these techniques may be expected to increase the benefits obtainable from radioactivity logging.

Chapter 16

CALIPER AND TEMPERATURE LOGGING

Wilfred Tapper

The uses of caliper and temperature records are sometimes so interrelated that a discussion of one log presupposes a discussion of the other. Here, however, for purposes of clarity, the records and the tools used to obtain them are treated separately.

It is the purpose of this chapter to give an outline of the history, development, construction, and uses of caliper and temperature electrodes. A knowledge of the physical construction of both types of electrodes results in a clearer understanding of the data obtained and more efficient utilization of the logs.

The few anomalies cited as examples do not pretend to be comprehensive. The uses for the various logs listed surely do not exhaust present or future possibilities in the oil industry or in other fields.

The writer is indebted to Mr. H. K. McArthur, Mr. J. K. Reynolds, and Mr. W. D. Owsley, of the Halliburton Oil Cementing Company, for advice and criticism in the preparation of this chapter.

CALIPER LOGGING

Even in the early days of cable-tool drilling, oil men were well aware that drill holes did not stand true to gauge. As holes were drilled deeper and exploration moved southward into the Gulf Coast area, this fact became painfully obvious.

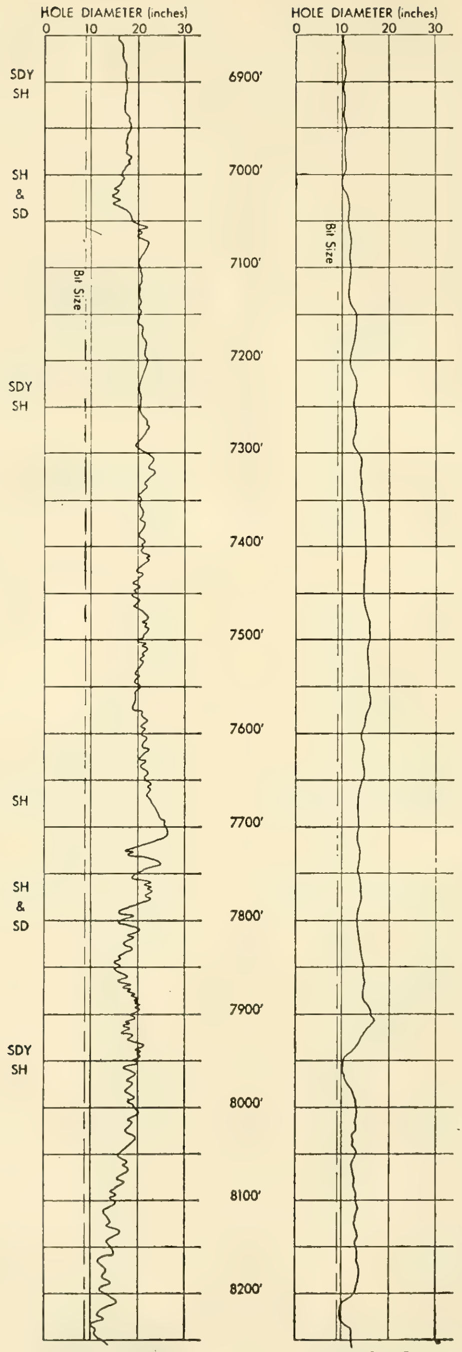

FIGURE 16-1. Caliper logs of two wells in Mercy field, Texas, showing influence of type of mud on caving.

One of the factors influencing the development and use of the rotary drill was its ability to cut through young, unconsolidated sediments and still have the bore hole tend to stand up. Nevertheless, numerous problems connected with rotary drilling and oil producing were a direct result of hole caving in rotary wells. The exact nature and extent of this caving was unknown. Every driller and every geologist had a theory, but there was no exact knowledge. Subsurface bore-hole caving was likened to surface erosion, but owing to the different character of the sediments and the greatly accelerated subsurface erosional forces, this parallel could not be drawn too far.

Present knowledge indicates three major reasons for differential hole size in a hole drilled with rotary tools: (1) action of the drilling fluid, (2) action of the bit, and (3) action of the drill pipe. Of these, it is believed that the action of the drilling fluid is most important.

The hole change caused by mud or any conventional drilling fluid is due either to a chemical effect (hydration) or a mechanical effect (attrition or dissolution). Of these two, it is believed that the former is the more important cause.

Water-base muds must have a tendency to cause many shales to swell and heave or to disintegrate. Many shales disintegrate beyond the 32-inch range of the modern caliper tool. Interestingly enough, a mud cake may be built up on the face of a formation, causing a hole to caliper smaller than bit size.

In order to reduce hole change, many muds other than water-base muds are used. Oil-base, oil-emulsion, silicate-base, and salt-base muds are all commonly used to prevent the caving of shales or soluble formations. It is not the purpose of this chapter to discuss the merits of various types of muds. The effect of these muds on hole size has been clearly shown to the industry by caliper logs. Figure 16-1 shows caliper logs on offset wells, one drilled with oil-base mud and one with water-base mud.

In 1932, M. M. Kinley made a successful attempt to caliper a hole. A few years later R. B. Bossler measured the enlargement of a hole caused by shooting. These early tools measured a short section of the well and were used mostly in shallow areas. The original Kinley caliper had four separately actuated arms, each arm giving a separate record. A stylus-recorded strip chart was obtained.

The present modern caliper used by the oil industry was developed from the original M. M. Kinley tool by the Halliburton Oil Well Cementing Company in 1940.

The present caliper is a chrome-plated tool three inches in diameter and approximately five feet long. It consists of an oil-filled chamber containing the electrical components, the four caliper arms, and the releasing mechanism. The tool itself is standard equipment on an electrical-service truck and is run in a well on a 5/16-inch logging line.

The four spring-actuated arms of the tool contact the walls of the bore hole when they are released. The motion of these arms is transmitted to a rheostat inside the oil-filled chamber by means of a flexible bronze cable-and-pulley system in such a manner that the change in resistance of the rheostat is always proportional to the change in average diameter as measured by the four arms. Owing to the spring tension in the arms, the tool will be approximately centered in the well, unless the hole is considerably off vertical.

The arms are held in a closed position by a steel band when going in the hole. This band can be broken at will, either by firing a brass projectile located underneath or by spudding on bottom.

The chamber of the tool is filled with oil and kept hydrostatically balanced by means of a large rubber diaphragm, which acts as a volume equalizer between the oil and the mud, compensating for the difference caused by the motion of the push rods and by changes in temperature.

A constant direct current is supplied to the rheostat in the tool, and the resultant potential drop across it is measured and recorded as a caliper log. These logs take the form of a continuous galvanometer trace recorded on film showing the average diameter of the bore hole, recorded as a function of depth.

A study of numerous caliper logs soon leads one to the conclusion that caving patterns exist. Certain generalizations may be made as to the relative ability of rocks to stand up to bit size. These generalizations are shown in graphic form in Table 16-I.

TABLE 16-I

Ability of Rocks to Stand Up to Bit Size

Rock	*Poor*	*Medium*	*Good*
Sand	----	x	x
Shale	x	----	----
Chalk	----	----	x
Limestone	----	----	x
Dolomite	----	----	x
Anhydrite	----	----	x
Salt	x	----	----

Although similar drilling conditions and similar muds tend to standardize caliper logs, some astonishing long-range correlations may be made by using them, even for wells drilled under entirely different circumstances. In the west Texas area, a number of horizons may be recognized on caliper logs, from Upton County, Texas, to the Hobbs Field, Lea County, New Mexico, a distance of 120 miles. Here caliper-log correlations are more trustworthy than those made with electric logs.

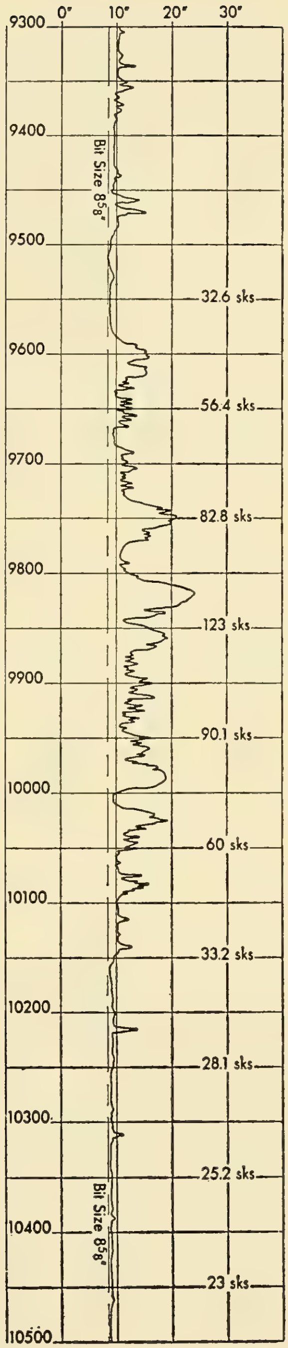

FIGURE 16-2. Caliper log of well in Smith County, Texas, showing effect of hole size on cement calculations.

The most obvious use for the caliper log in the oil industry is as a tool to calculate the proper amount of cement necessary to fill up the annular space between the casing and the open hole to a desired point. The actual amount of cement necessary for a desired fill is often two or three times the amount one would use from theoretical calculations. Figure 16-2 is an actual caliper log of a well in Smith County, Texas. The hole was drilled with an $8\frac{5}{8}$-inch bit, with $5\frac{1}{2}$-inch casing set on bottom. Theoretical fill-up is 22 sacks of cement per 100 feet of hole. For more than 1000 feet of section 220 sacks of cement is the theoretical amount necessary to fill back to 9500 feet. The actual amount of cement needed is 544.4 sacks, or more than twice the theoretical quantity.

Another problem encountered in the successful completion of an oil well is the location and reaming of tight spots in the hole, so that casing can be set and successfully cemented without channeling and bridging. The value of a caliper log in locating these zones has been demonstrated many times.

Modern drilling practices presuppose the use of many scratchers, centralizers, and guides welded to the casing to assist in obtaining a better cement job. All these tools have proved extremely useful in obtaining better cementing jobs and eliminating costly squeeze jobs, but they are useless unless properly positioned in the hole with the aid of a caliper log.

In plugging back with cement, plastics, or gravel packing, a knowledge of hole size is invaluable. In remedial work of this kind, well records are usually inaccurate or nonexistent, and it is only through an application of the knowledge gained from a caliper log that a successful job may be performed.

In the field of drill-stem testing, a knowledge of caving conditions has saved oil operators an untold amount of money. Figure 16-3 is a caliper log of a well in Smith County, Texas, where the operator wished to find a packer seat to drill-stem test the Paluxey sand at 7140 feet. A glance at the log will show that, using trial-and-error methods, the chances of successfully setting a packer are relatively small. By applying the information to be gained from the use of a caliper log, the proper point to set the packer and the proper size of packer are easily determined.

Many other uses have been found for caliper logs. The successful completion of a fishing job may depend on a knowledge of the size of the hole above the junk. A log made after a fishing job is completed will provide the necessary data successfully to resume drilling operations.

A knowledge of hole size is essential in evaluating an acidizing job, picking a zone to side-wall-core, evaluating the results of shooting with nitroglycerine, and finding a proper zone to gun-perforate. The present caliper log has fulfilled all these functions.

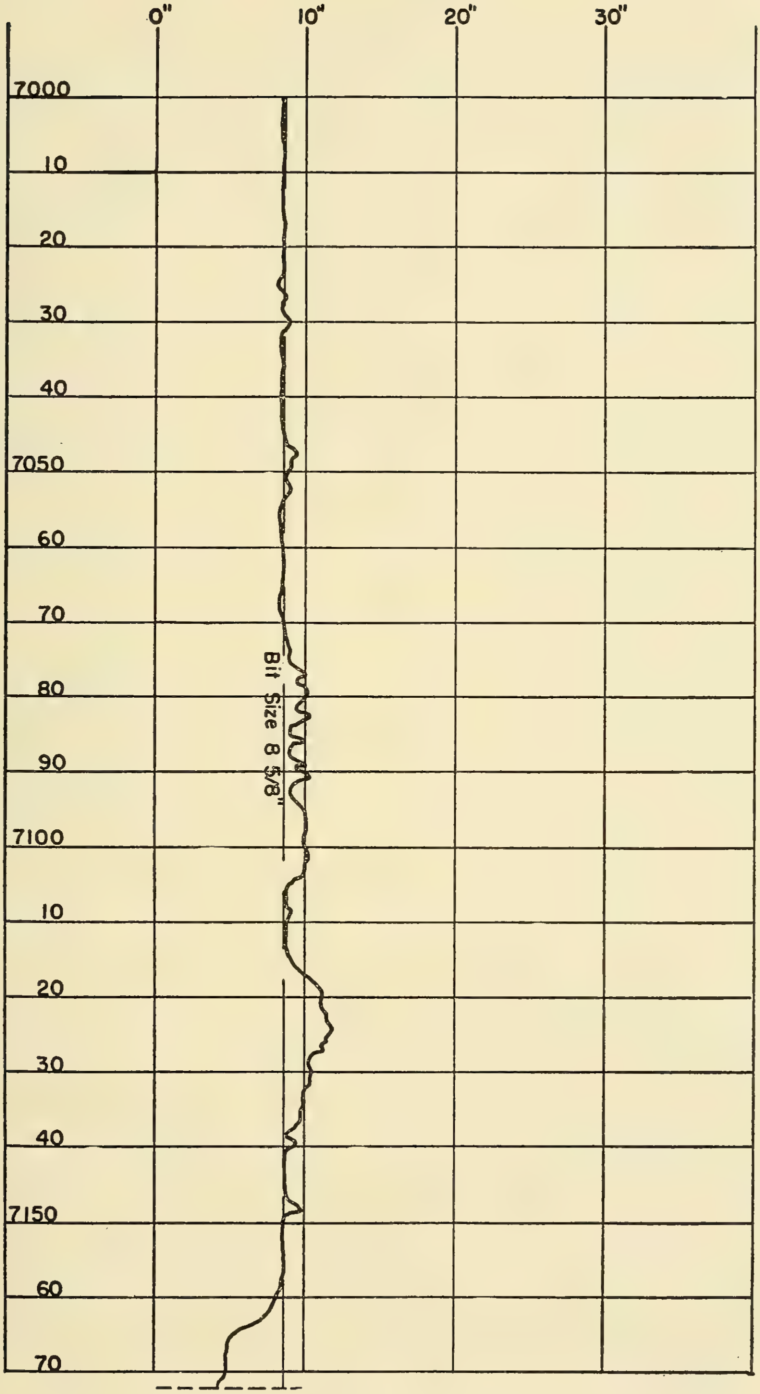

FIGURE 16-3. Caliper log in Smith County, Texas, used to find packer seat.

TEMPERATURE LOGGING As early as 1869 Lord Kelvin conducted experiments in measuring earth temperatures at a depth of 350 feet in the ground. Since then, geologists have speculated on the geothermal gradient in the earth's crust. Even with such an early start, little has been done in the way of quantitative work with earth-thermal measurements.

At the present time thermal measurements in either a cased or open hole are usually obtained by means of a continuous-recording, extremely accurate, electronic thermometer. Such a tool is standard equipment on an electric-logging truck and is run on a 5/16-inch conductor cable.

The temperature electrode is a 3-inch rubber-covered tool about 6 feet long. In a groove in the rubber coating of the electrode is a 20-inch length of platinum wire, which is exposed to the mud column. This wire is small in diameter and assumes the temperature of the fluid around it rapidly. Changes in temperature produce changes in the resistance of the wire, which are detected by a bridge circuit in the electrode. Alternating current from a 500-cycle generator is supplied to the bridge terminals. The signal terminals of the bridge are transformer-coupled to the grid-cathode circuit of an a.c. amplifier circuit in the tool. The amplified a.c. signal is rectified and sent to the surface as a d.c. signal, where it is calibrated in degrees. In order to cancel the static value of this signal, a known matched signal of opposite polarity is placed in series with the electrode signal. The resultant d.c. signal is amplified in the instrument tray and recorded in the camera. A switch is provided in the tool for changing signal points at the a.c. bridge, so that the bridge can always be operated close to the balance point. This is necessary for two reasons, to reduce noise and to keep the electrode system from being saturated. The resultant log comes as a plot of temperature versus depth.

The standard electrode may be obtained in two temperature ranges, from 20F to 280F and from 60F to 340F. Tools capable of being run in tubing are also made.

A fundamental knowledge of temperature gradients and temperature anomalies, as expressed in drilled holes, is necessary before the myriad uses of temperature logs can be fully realized.

Measurements made by a thermometer lowered in a drill hole give the temperature of the drilling fluid. Unless the hole has not been circulated for several weeks, the temperature of the mud is very different from that of the formations. The mud is usually colder at the bottom and hotter at the top of the hole than is the surrounding strata. Thus, when circulation is stopped, the mud will warm up in the lower part of the hole and cool at the top. The speed of this heat exchange will depend on the lithology of the bore hole.

To illustrate this, take a well 800 feet deep, as illustrated in Figure 16-4. The geothermal gradient can be represented by a straight line, as shown in curve 1. The temperature of the mud, when circulation ceases, is almost the

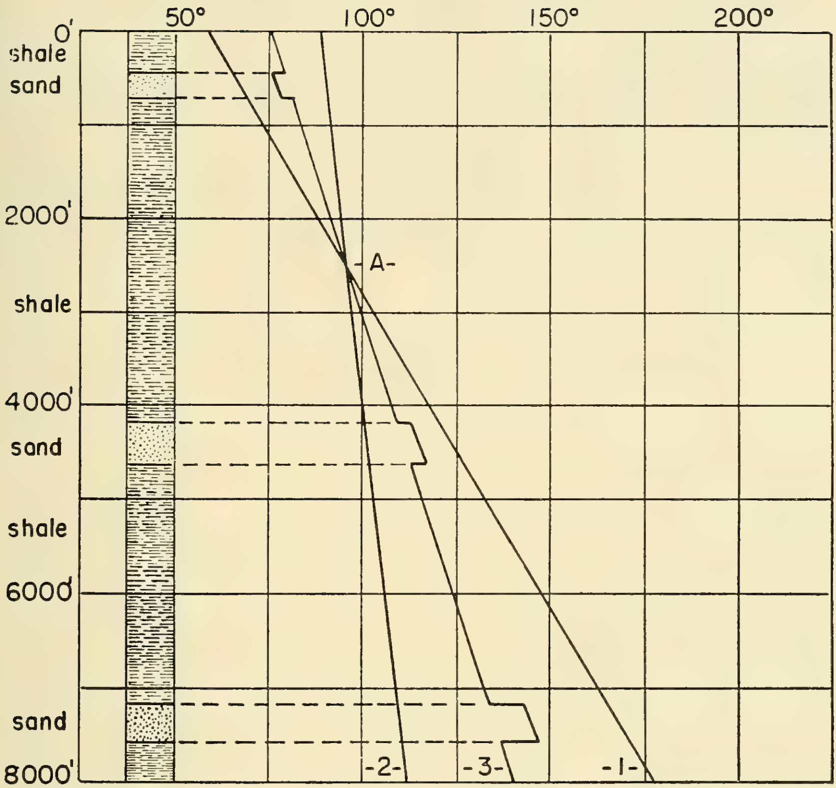

FIGURE 16-4. Chart showing temperature gradients.

same from top to bottom, as indicated by curve 2. The temperature gradients cross at point *A*.

If the well is left idle for several days, the temperatures will tend to equalize and the mud curve will tend to rotate from 2 to 1 about the axis *A*.

The cooling or warming of the mud at a certain depth will depend on the thermal conductivity of the formations and the size of the hole. Experience has shown that equilibrium is reached sooner opposite sands than shales. This can be explained by the fact that (1) hole size is smaller opposite sands than shales, and, therefore, the volume of the mud is less, and (2) the thermal conductivity of sands is greater than that of shale.

Thus it will be seen that during thermal evolution, sands will exhibit a lesser temperature than adjacent shales in the top part of the hole and a higher temperature in the bottom part. Curve 3 of Figure 16-4 represents the temperature of mud about ten hours after circulation and illustrates this point.

If a temperature record is obtained immediately after circulation, a flat curve resembling curve 2 of Figure 16-4 will result. The same type of curve will be obtained after several days have passed and equilibrium has been reached. The most pronounced anomalies are obtained 24 to 36 hours after circulation has ceased.

Although from the foregoing discussion one can see that it is possible to distinguish sands from shales, the temperature log will not yet replace the electric log. Factors such as chemical reaction, changes in hole size, the movement of fluids between sands, and the movement of hydrocarbons can alter the temperature in a well.

Thus far only open-hole-temperature measurements have been considered, but the presence of a string of casing does not disturb the thermic state of a bore hole. Therefore, all of this previous discussion applies to cased holes when they have been cemented, provided the temperature log is made four or five days after cementing.

Cement generates considerable heat as it sets up, and this factor has resulted in the principal application of temperature logs—the determination of a cement top behind casing by means of thermal measurements. The magnitude of this temperature increase varies with the time elapsed since cementing and the quantity of cement used.

Most of the heat is generated a few hours after the cement job has been completed. After this interval it is quite possible that the formation will absorb heat faster than it is generated by the setting cement, thereby cooling the mud. As a rule the best time to run a temperature survey is from four to eighteen hours after the cementing plug has hit bottom. The exact interval depends on a number of factors. Most operators prefer not to release the pipe pressure until after the initial set of the cement, which is a function of the type of cement, the type of water, the temperature, the pressure, and other variables.

The quantity of cement also affects the magnitude of a temperature anomaly. The amount of deflection tends to vary as does the amount of cement, which is a function of hole size. The joint use of a caliper log when trying to interpret a temperature log is often useful in this respect.

Several precautions should be taken when obtaining temperature logs in a cased hole. Circulation after cementing has been completed, results in the heat evolved by setting cement being dissipated, and a trustworthy record is not obtained.

Temperature surveys in their present form will tell how high cement is in the annular space and, comparatively, how much cement is behind pipe. However, the survey does not indicate where the cement is distributed. It is, for all practical purposes, impossible to detect channeling on a cement job by means of a temperature survey.

Numerous other uses have been made of temperature records in both cased and uncased holes. As gas enters a well, either through a hole in the casing or into a bore hole on an uncased well, it expands and cools. This characteristic has been used to find oil-gas contacts or a hole in the casing. However, any use of a temperature log presupposes that the temperature anomalies being measured are of a greater magnitude than four of five degrees, these being the order of formation thermal differences.

Reprinted from *Subsurface Geologic Methods*, 1951, p. 439-449.

Chapter 17 MUD AND CUTTINGS LOGGING

W. H. Russell

As the drilling of a well progresses, the bit dislodges and disintegrates a cylindrical section of the formation. As the cuttings travel upward and as the hydrostatic pressure in the mud column decreases, any gas in the pore space of the cuttings will expand. A portion will escape to, and be entrained in, the drilling mud and a portion will usually remain in the cutting. In an oil-bearing formation, the associated gas will expand and force a portion of both oil and gas into the mud stream, while a portion of each remains in the cuttings. These hydrocarbons can be detected with sensitive equipment when the mud and cuttings reach the surface. By continuous analysis of the mud and cuttings and by making suitable allowance for time necessary to reach the surface, the oil- and gas-bearing formations can be detected and their depth determined.

EQUIPMENT

The equipment used in mud-analysis and cuttings-analysis logging involves three groups:

1. Equipment used directly in making determinations of oil and gas.
2. Equipment used to relate shows to depth of origin.
3. Auxiliary equipment.

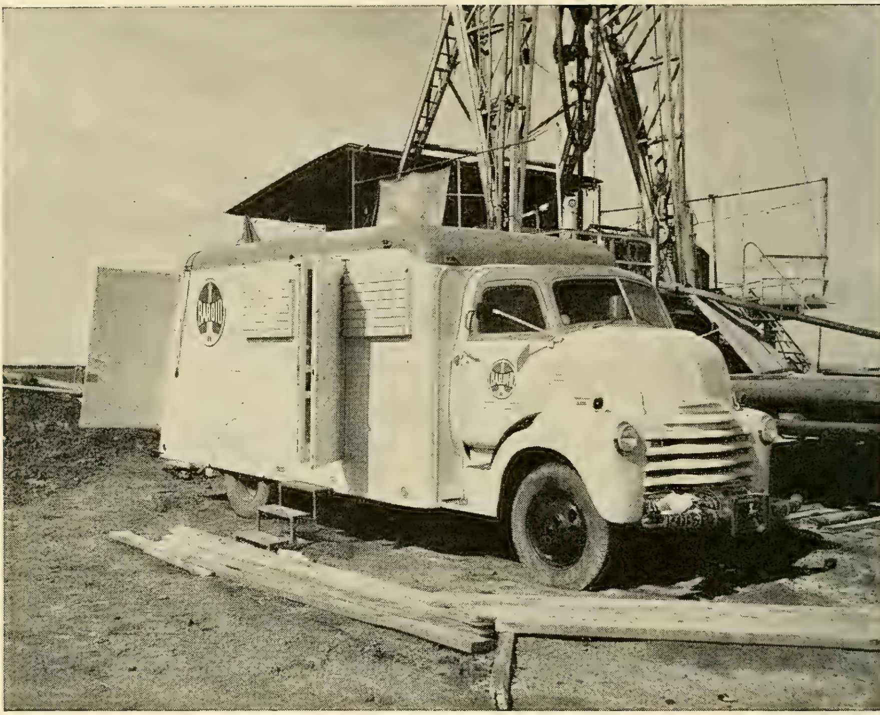

FIGURE 17-1. Well-logging unit on location.

Arrangement of equipment in the well-logging unit (fig. 17-1) is shown in Figures 17-2 and 17-3.

The apparatus used for determining the gas in drilling mud consists of a gas detector and a gas trap through which a small stream of mud returns are diverted. The mud is agitated in the presence of air to allow separation of gas from the drilling mud. From this trap a small vacuum-pump compressor delivers a stream of the air-gas mixture to a hot-wire gas detector, where the gas content of the mud is determined.

The hot-wire gas detector is an adaptation of an instrument that has been used to detect combustible gases in coal mines. Provisions have been made to operate the filaments alternately at two temperatures. At the higher temperature, all combustible gases are burned; and at a lower temperature, only the heavier molecular-weight gases are burned. Thus, the difference between the two is a measure of the methane.

In determining the amount of gas in cuttings, a measured quantity of the drill cuttings is placed in an agitating device with a measured quantity of

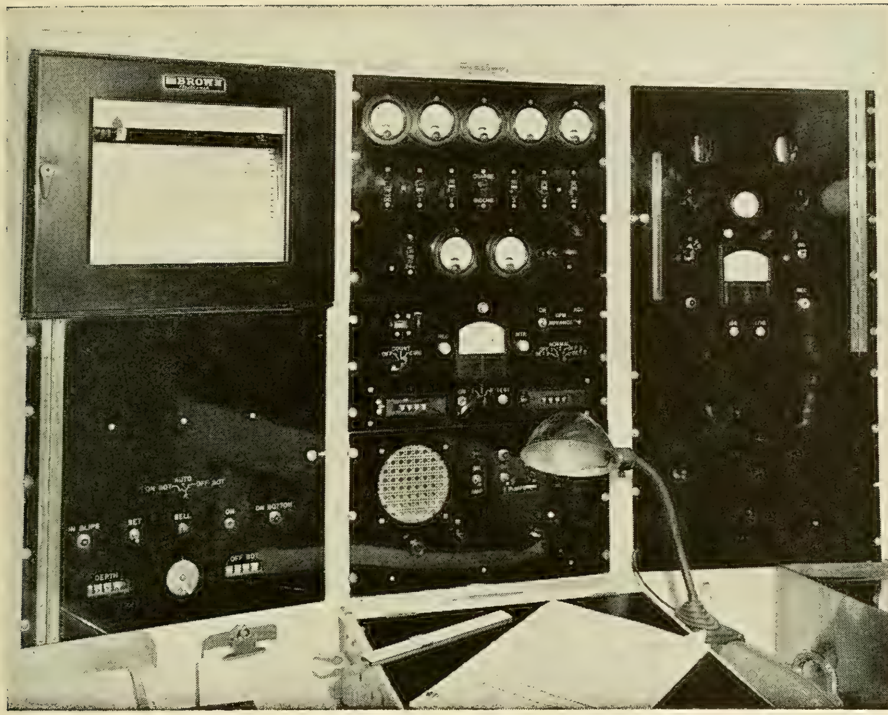

FIGURE 17-2. Instrument panel for well-logging unit.

water. In this device the cuttings are violently agitated and broken up. After the agitation period, readings are taken from one or, in more advanced equipment, two sets of filaments in the container. On one set of filaments all combustible gases and then heavier hydrocarbons are indicated in the same manner as the mud-gas analysis. The second set of filaments indicates hexane and heavier hydrocarbon gases in the cuttings and are indicative of oil. Lighter hydrocarbons—methane through pentane—are normally not detected by these filaments but may affect the readings if the amount of C_6+ is considerable.

The ultraviolet-light method is used to detect oil in both the drilling mud and the cuttings. A sample of drilling mud, representative of that which flushed the bit while a certain interval of the hole was being drilled, is collected at the mud-flow line and is treated to reduce viscosity and to allow the oil to break out and rise to the surface of a shallow dish that is placed in the ultraviolet-light viewing box, where it is alternately subjected to ultraviolet and white light.

It is usually possible to distinguish between crude oil and the rig oils and greases by close examination of the particles which fluoresce on the surface of

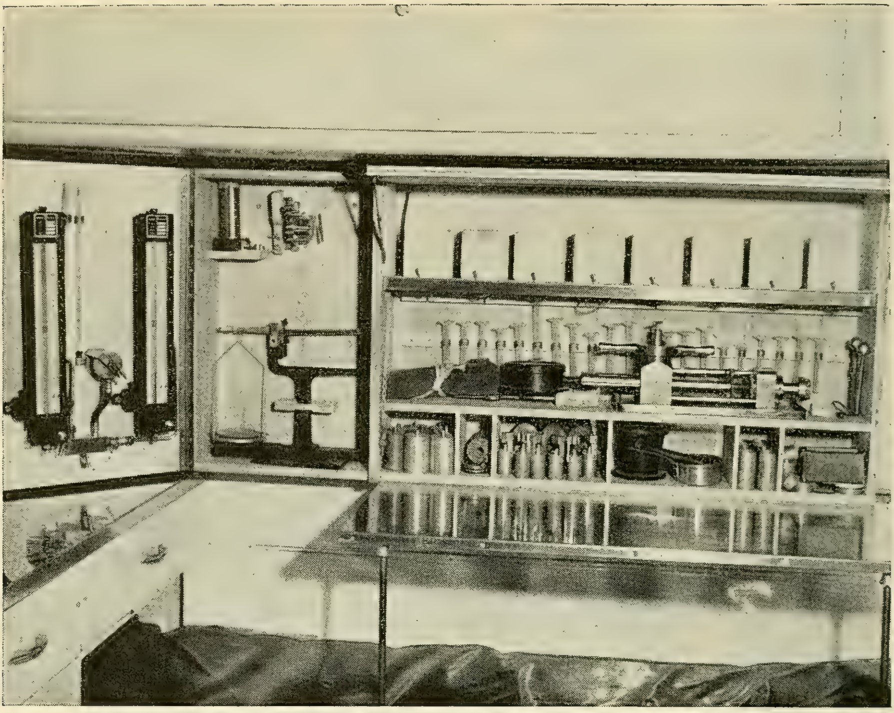

FIGURE 17-3. On-location core analysis equipment in well-logging unit.

the treated mud sample and by comparison of the fluorescent particles to samples of rig oils and greases.

In determining oil in cuttings, it must be borne in mind that the fluorescence of the cuttings may be mineral fluorescence. Calcite is the principle mineral encountered that may cause interference. It is possible to distinguish easily between mineral fluorescence and oil fluorescence by placing particles that fluoresce in a nonfluorescent solvent such as carbon tetrachloride and observe them under the ultraviolet light. If fluorescent material is leached out of the fluorescent particles and the solvent becomes fluorescent, the indication is that oil is in the particles. If, on the other hand, the fluorescence does not spread to the solvent, the fluorescence is assumed to be due to the fluorescent minerals.

As indicated above, the presence and relative amount of gas in the mud and cuttings is determined by the hot-wire gas detector, which gives a meter reading that is independent of the observer. However, in the present oil-detecting methods, the judgment of the operator of the equipment is relied upon to determine the presence and relative amounts of the shows of oil observed in the mud. In the cuttings, oil is detected both visually by use of the ultraviolet light and instrumentally by the filaments that measure the heavier hydrocarbons. Mass spectrometers, gas chromotographers, and other complicated equipment have been used for a more complete breakdown of hydrocarbons. The additional information thus obtained has not proved of value, however, in predicting the commercial possibilities of a formation.

The equipment necessary to relate shows to depth are the depth meter and counters that register the actions of the mud pump and the circulation of the mud. The depth meter used is an instrument that operates automatically, once it is set with the depth of the bit at some point in the hole. It is used to measure changes in depth from that point and does this job automatically and quite accurately. For technical reasons, however, no attempt is made with this apparatus to measure the depth of the hole from the surface.

In relating the oil and gas shows to depth, it is neccessary to follow the movement of the drilling mud and the cuttings, which it carries, from the time the mud leaves the bit until they reach the surface. The use of clocks for making this determination is based on the assumption that the circulation rate of the mud is constant. Actually, this assumption is dependable in most instances, but there are times when it is not valid. It is preferable, therefore, to consider the pump as a displacement meter and to count the number of strokes it makes as an indication of the volume of circulated mud.

By using such tracers as cellophane strips, oats, or, if conditions allow, carbide, which are placed in the drill pipe at the surface, one is able to determine the number of pump strokes required to circulate mud through the hole. Because the volume of the drill pipe and the output of the pump are known, the number of strokes required to pump mud from the surface to the bit can be fairly accurately determined. This number of strokes is subtracted from the number required for complete circulation of mud through the hole to give the amount of pump action required to circulate mud from the bit to the surface. By making accurate observations of the pump-counter readings at certain depth intervals, one can determine the bit depth.

Auxiliary equipment, which is not essential to the logging method but which is used to reduce the burden of work on the operator and to give additional valuable information, consists of (1) an automatic recorder that indicates the gas shows and the action of the pump, together with changes in depth; (2) a pump-rate meter that is used in determining washouts of the drill pipe and in some instances the development of a gas blowout; and (3) binocular microscope for inspecting the lithology of the cuttings.

From information obtained by the operator and described above, a log is then prepared as illustrated in Figure 17-4.

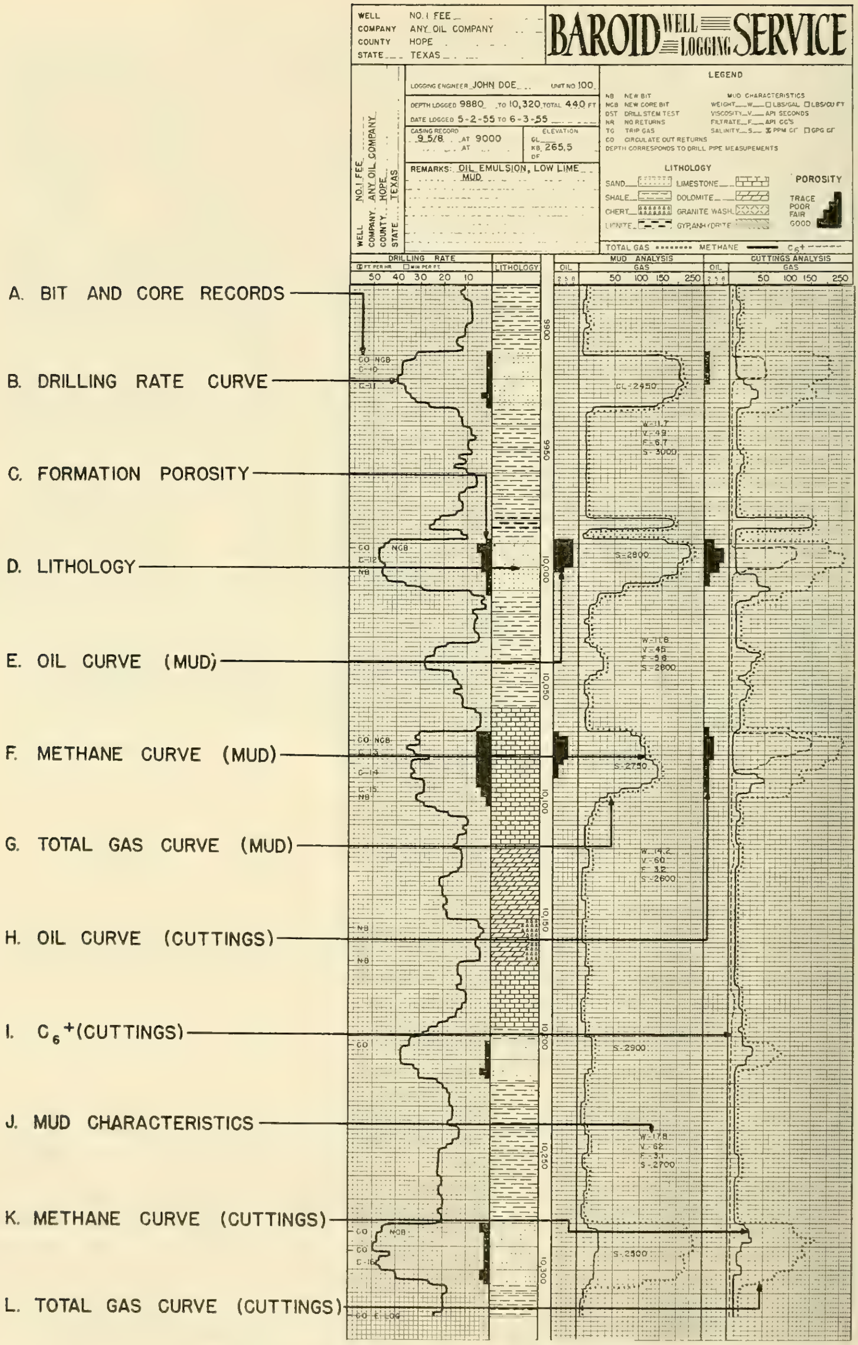

FIGURE 17-4. Mud- and cutting-analysis log.

FACTORS INFLUENCING AMOUNTS OF OIL AND GAS IN CUTTINGS

Many factors influence the relative amounts of oil and gas in the drilling mud and cuttings when an oil-bearing formation is penetrated. The following are the most important: (1) flushing or water-flooding action of the mud filtering at or ahead of the bit; (2) pressure balance between the mud column and the formation; (3) factors related to the type of porosity, shape of pore space, and permeability of the formation; (4) rate of drilling; (5) rate of mud circulation; and (6) characteristics of the drilling mud such as density or weight, filtration properties, and viscosity and gel properties.

The following brief discussion illustrates how these factors influence the amount of oil and gas in the mud and what happens to the formation fluids near the drilling bit as an oil-bearing formation is penetrated.

In the first place, the fluid pressure asserted by the drilling mud is normally greater than the fluid pressure in the formation. There is a tendency, therefore, for the drilling mud to be forced back into the exposed surfaces of the formation. Solid particles of the mud are filtered out and deposited on the surface of the formation as a filter cake while water from the drilling mud penetrates the pores of the permeable formation.

The laws governing the deposition of filter cakes and rate of filtration of drilling mud are believed to be the same as the general laws of filtration, which have been well established in engineering practice. The rate of filtration at any time after the start of the filtration process is inversely proportional to the square root of time, or:

$$\text{filtration rate} = \text{a constant} \div \text{square root of time}$$

When the bit rotates on the bottom of the hole, it either chips off the formation on which the previous mud cake has been deposited or scrapes off the mud cake and re-exposes the formation so that the conditions prevalent at the bottom of the hole are such that the mud filtration rate remains relatively high because the cake is being removed or rapidly disturbed. Even with muds having the best wall-building properties, there are ample possibilities for filtration to occur ahead of the bit.

Just below the bit, formation water flooding occurs and reduces the oil and gas content of the formation but does not remove the oil and gas completely, in much the same manner as secondary recovery. Some of the oil and gas is held by the capillary forces active in the formation pore space. The bit chips off particles of the formation; the cuttings join the mud stream and are normally carried to the surface. At the same time, the gradual reduction of pressure on the fluids in the formation pores allows expansion of the fluids in the pores. The gas expands greatly and pushes some of the oil and water out of the cuttings into the stream of drilling mud. Some oil also joins the mud stream when the fractured formation surface is exposed by the bit action.

When the cuttings reach the surface, they are therefore in a general water-flooded condition. The cuttings do not contain amounts of oil and gas that are quantitatively indicative of the amount of oil and gas that may be present in the formation. The cuttings are in about the same condition, as far as their fluid content is concerned, as a core when it reaches the surface, except for being slightly more water flooded.

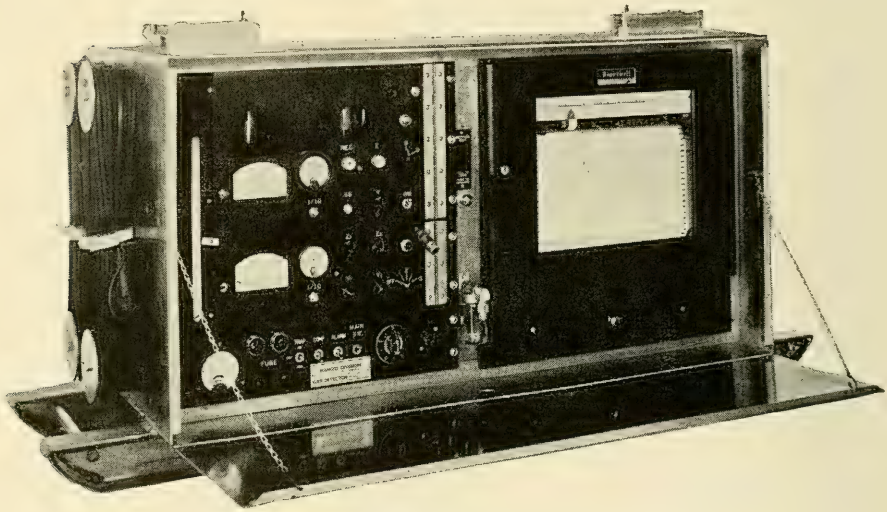

FIGURE 17-5. Automatic recording gas detector.

CONCLUSIONS

The following conclusions are borne out by experience:

1. The amounts of oil and gas in either the drilling mud or the cuttings are a *qualitative* indication of oil and gas in the formation.
3. Except under unusual conditions, reliable shows are obtained in both drilling mud and cuttings.
3. Conditions allowing large shows of oil and gas are those that contribute to a minimum amount of loss of oil and gas from the drilled formation by water-flooding action. These are (a) high drilling rate; (b) medium to low formation permeability; (c) low pressure differential between the mud column and formation; and (d) mud of low filtration rate.

4. Conversely, those conditions that contribute to minimum shows of oil and gas in the drilling mud are (a) abnormally low drilling rate for permeable formations; (b) high mud weight or pressure differential between the mud and the formations; (c) high permeability; and (d) low porosity.

Reliable shows are usually obtained in the cuttings, except in unconsolidated sands where the formation fluids mix with the mud stream or where circulating rate or hole conditions and mud properties are such that the cuttings are not transported readily to the surface, where they can be collected and properly related to their depth of origin.

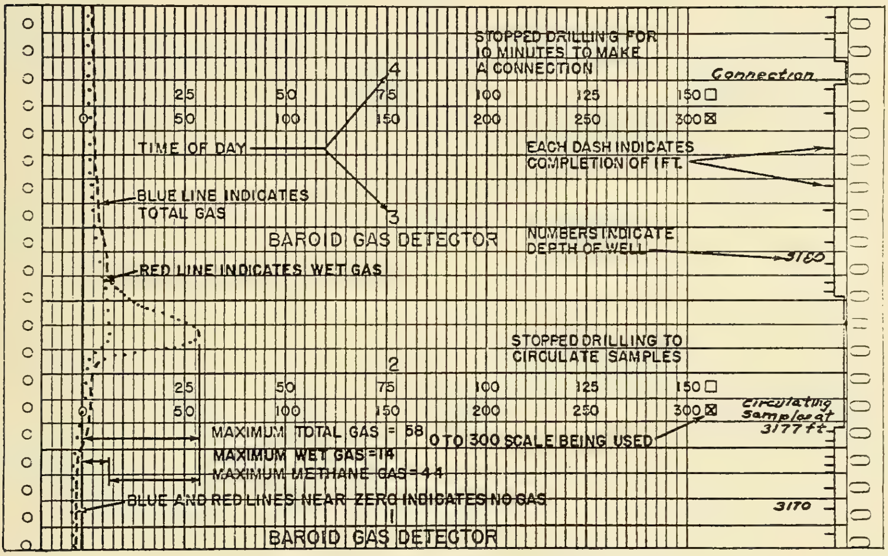

FIGURE 17-6. Automatic recording gas detector chart.

Relatively large shows of gas in the cuttings are obtained where the formations have extremely low permeability and contain gas under high pressure. To be sure of getting the indications of formation oil and gas under all conditions, it is necessary to resort to both drilling-mud and cuttings analyses. Zones of commercial importance will always be reflected in the drilling-mud analysis.

Where circumstances make it impractical to use the logging service described above, mud and cuttings analysis may be obtained through the use of an automatic gas detector (fig. 17-5). This detector utilizes the same gas-detecting equipment but does not require an operator on duty 24 hours a day. An alarm is set to signal an increase in gas when the instrument is left unattended.

The two gas curves, total gas, and heavier hydrocarbons are recorded by a strip-chart recorder (fig. 17-6). The drilling rate may be recorded on the same chart by an electrical connection with a geolograph or similar instrument. Shows may be correlated with their proper depth by making a suitable allowance for lag time. Thus, the interested party has at all times a permanent up-to-date record of the most important factor in mud logging—indications of hydrocarbons in the drilling mud corrected to the depth from which they came.

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Chapter 18 DRILLING TIME LOGGING

G. Frederick Shepherd

Rate of penetration is considered here as the time required to rotary-drill a linear unit of depth of a geologic formation. It is believed that drilling-time characteristics constitute a diagnostic property of a rock resulting from its composition, mode of deposition, degree of compaction, and other physical features by which the rock is described. At present, drilling-time properties, measureable in terms of rate of penetration, are qualitative in scope and relative in their interpretation. That they may become quantitative and definable in fixed values which may be significant in the determination of lithologic types is anticipated.

Rate of penetration may be measured in terms of drilling time and drilling rate, each of which has its own specific uses and limitations. The relationship between the two and their differences are discussed. Drilling-time data may be applied to many engineering and drilling problems and have proved of considerable value to contractors, drilling crews, and operators. The multiple uses to the geologist involve general correlation problems and lithologic studies. The geologic application of drilling-time data is an additional technique of particular value in the determination of potentially productive sections of a well bore and in the calculation of recoverable reserves.

Many methods have been used to measure and record drilling time. A technique used by the author is described and illustrated in which mechanical recording of depth in reference to elapsed time is translated into graphs or logs, which may be used in the solution of many geologic and engineering problems. The amount of section so logged and the scale employed are determined by the requirements of the individual problem. Detailed instructions are included whereby a geologist not experienced in the use of this technique, may learn how to prepare and interpret drilling-time logs in any area in which he may be interested.

DEFINITIONS

Early methods of determining rate of penetration were crude and approximate and generally consisted in recording the time required to drill a certain number of feet of hole or the number of feet drilled per hour. Data thus acquired may be adequate for some purposes, but as the technique of using drilling time became more widely employed, certain advantages were observed in determining the specific net amount of time required to drill each foot. Before discussing the application of drilling-time data, the distinction should be understood between drilling rate and drilling time.

By definition, rate of penetration is a fixed lithologic property, even though it may be diagnostic only when used as a relative term. *Drilling time is the duration of time required in the actual drilling of a unit of depth. Drilling rate is the number of units of depth drilled in a unit of time.*

The foregoing may be illustrated by comparison to an automobile speedometer. When a car travels a mile in a certain number of minutes and seconds, it is a measure of speed comparable to the time occupied in the drilling of one foot of formation, which we have defined as drilling time. When a speedometer indicator points to 45, it indicates that the car is traveling at the rate of 45 miles per hour. This is comparable to rate of penetration measured in the number of feet drilled per hour, which is the definition given for drilling rate. The distinction is more than academic and should be clearly understood, because the interpretation of rate of penetration is strongly influenced by the method of recording.

DRILLING TIME: DIAGNOSTIC OF LITHOLOGY

The relationship between rate of penetration and lithology has been understood for many years. The application of drilling time was recognized at least seventy years ago, and the interpretative value has been appreciated for more than twenty years. The use of drilling-time data has widened continuously as mechanical devices for their recording have become available and new applications of the data have been found.

Drillers probably were the first to learn that a change in drilling rate meant a change in the type of rock penetrated by the bit. Limestone, anhydrite, shale, or sandstone would be recognized prior to confirmation by examination of the cuttings. Until recently the application of drilling-time data was essentially one of qualitative significance, and methods of observing rate of penetration were formerly far from exact.

Regardless of the method of observation or the crudeness of technique in measuring drilling time, one fact remains unchanged and should be emphasized. Drilling-time characteristics are but one of many diagnostic properties of a rock; therefore, the use of rate-of-penetration data must be considered as corroborative of other techniques by which lithologic properties are recognized. Sample examination, coring, electric, and radioactivity logging, temperature and caliper surveying, drilling-time logging, and other means of geologic observation must go hand in hand to accommodate today's demand for more scientific methods for finding oil and gas reserves.

If, when drilling under uniform conditions, the bit's penetration changes from a slow rate to a faster rate or vice versa, it is an indication that a new type of lithology has been encountered. The obvious examples are readily recognizable and well known. A driller could hardly fail to know when he has encountered anhydrite or a sandstone by "the way the bit acts." Certainly a change from crystalline limestone to dense dolomite or from hard shale to limestone is more difficult to observe, but any change in the characteristics of lithology should cause a change in the rate of penetration, provided all other factors remain constant.

One might question whether rate of penetration is scientifically a property of a rock because, at the present time at least, it is not capable of being catalogued in quantitative terms. This is a weakness in technical procedures, or the fault may be the inability to evaluate contributing factors, but this does not alter the fact that rate of penetration is a petrographic property. If there were no means of determining the identity of mineral constituents of a rock, it would not be wrong to state that mineral composition is a diagnostic property by means of which a specific lithologic type could be identified.

It can not be claimed that a certain sandstone having 90 percent quartz, 6 percent feldspar, 3 percent mafics, and 1 percent auxiliary minerals, for example, will drill at a rate of 1 foot in 3 minutes and 15 seconds; nor, conversely, that any rock which drills at that rate is necessarily that particular type of sandstone. Under one set of conditions it may drill in exactly that amount of time, and with other drilling conditions it may require much less or much more time. Nevertheless, we are defining rate of penetration as a fixed lithologic property, comparable to electric, radioactive, or mineralogic properties, and the hypothetical fixed time required to drill 1 foot of sandstone such as that described above could be defined as diagnostic of that rock.

It is hoped that some procedure for quantitatively evaluating contributing factors will enable drilling-time properties to be understood as fixed characteristics after allowing for the amounts of time required in the drilling of a unit of depth that are not attributed to the inherent lithology of the rock. Among the contributing factors referred to are the size of the hole, the type of bit, the drilling weight employed, the rotary speed, torque and friction, and the condition of the mud. This subject is worthy of study as a research project in order to determine the net-drilling-time value of a formation having uniform characteristics over an area large enough that adequate drilling-time data could be accumulated and studied.

The qualitative interpretative value of drilling-time data, however, is not impaired by the absence of quantitative calculations. Observations by the author in the drilling of hundreds of thousands of feet of hole have shown that drilling conditions are insignificant in comparison to lithology in determining the rate of penetration of a rock formation. Obvious exceptions have been noted, but the foregoing observation holds true. It has been shown in many instances that a change in formation will be reflected by a change in drilling time even when very dull bits have been in use or where other conditions would be expected to obliterate any evidences of change in drilling time. Perhaps the condition that affects drilling time more than any other is holding up on drilling weight as when straightening a hole tending to deviate. Under such disadvantageous conditions, there may be no pronounced change in the actual time required to drill a unit of depth when passing from one lithology into another, but the pattern of the curve plotted from drilling-time data seldom fails to reflect the change in lithology. Adverse drilling conditions do require more careful interpretation than favorable drilling conditions, but the effect of changes in lithology is seldom completely obscured.

Because drilling time is a qualitative property of a rock, it is important that correct identification of lithologies be based on the observation of relative values. A foot of hole that is drilled in 5 minutes at one depth may be interpreted as a sandstone, and another foot drilled under conditions differing from the first-mentioned foot requiring also 5 minutes for drilling may be interpreted as a shale. In each case the interpretation is based on the relative time in comparison to previously drilled feet. The value of the application of drilling-time data to geologic and engineering problems lies in the recognition of this relative interpretation.

DRILLING TIME AND DRILLING RATE

The two means of measuring rate of penetration have been defined; and, as shown, drilling time is a specific value for each foot, and drilling rate is an average value involving the drilling of several feet. The former is more exact and is useful where detailed lithologic information is re-

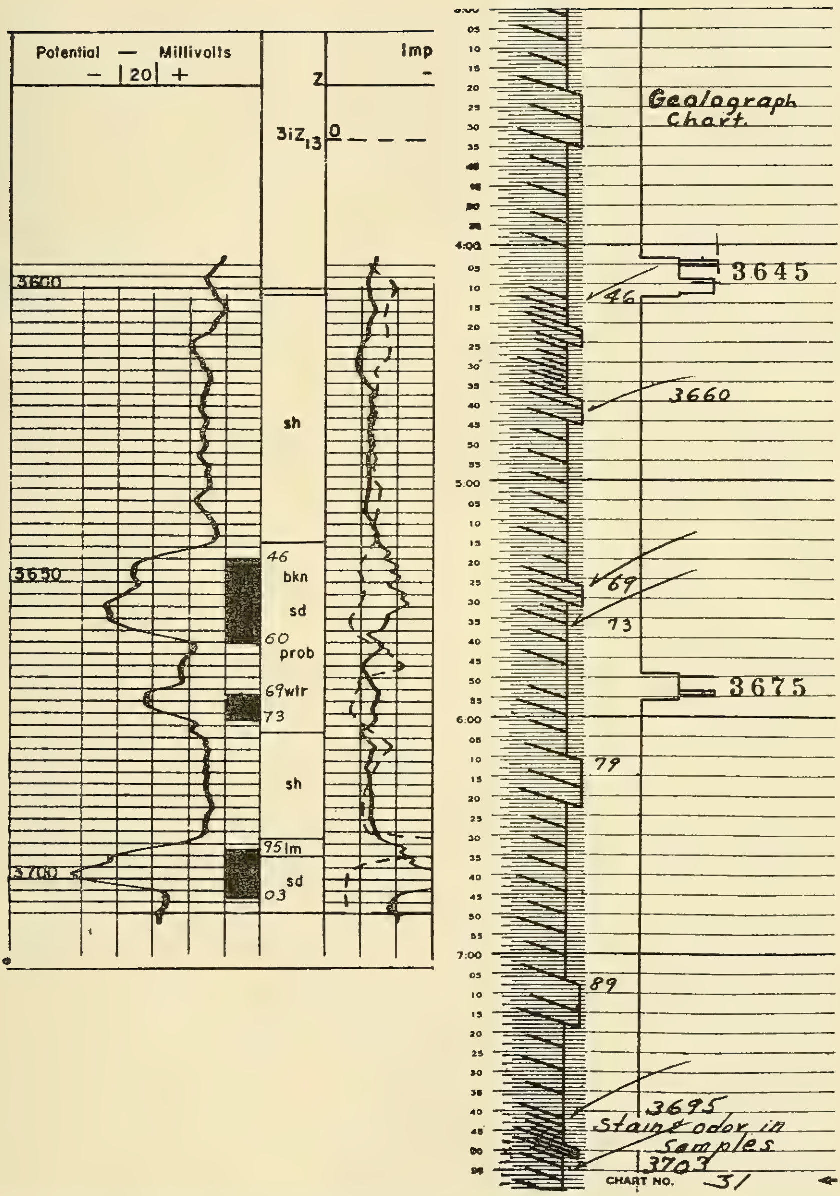


FIGURE 18-1. Relationship between electric log and drilling-time data. Black areas on electric log indicate intervals of a rapid penetration.

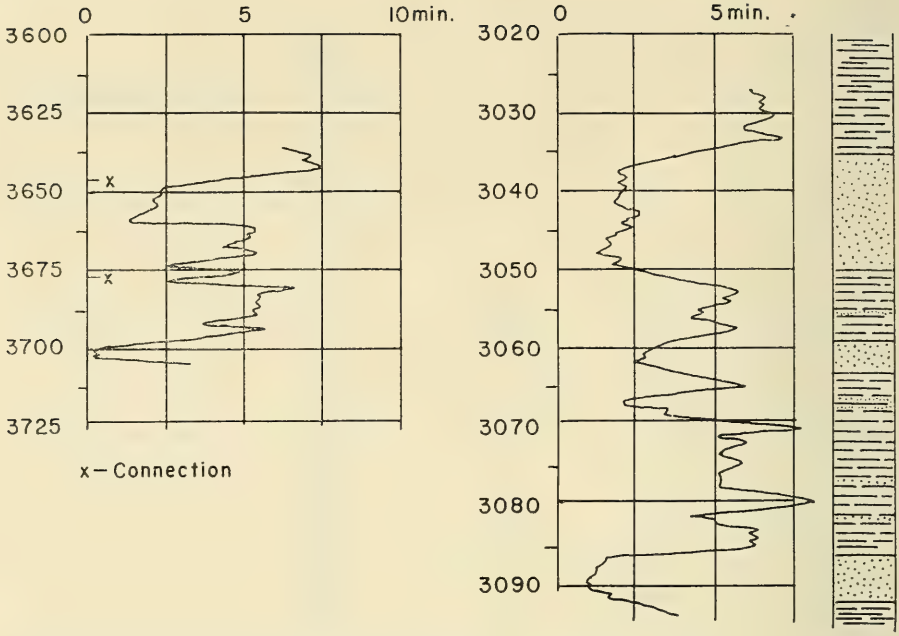


FIGURE 18-2. Two curves plotted from data on drilling-time chart of Figure 18-1.

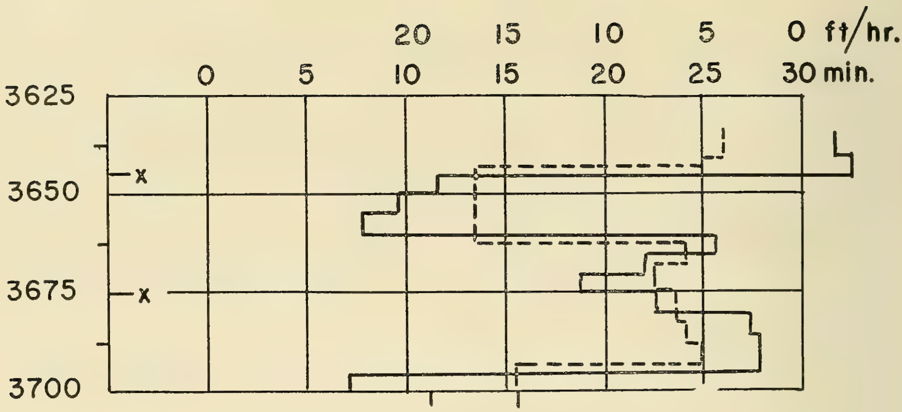
quired and where difficult correlation problems may be solved only in the study of minor features that are best disclosed in the pattern of a log plotted from drilling-time data. The latter method requires less time for recording original data and for plotting and is useful where rapid interpretations are required and where it is used in conjunction with other methods that are based on average data as well, such as sample-examination logs.

As will be shown further in this section the pattern revealed by a drilling-time log has characteristics very similar to that of an electric-potential curve. The differences between drilling-time and drilling-rate logs may be illustrated by the electric log of a well drilled and the original drilling-time record of the same well. In Figure 18-1 the porous sands are indicated by the relatively close spacing of the foot marks on the drilling-time chart and are confirmed by the electric log. It will be noted that the streak 3669-3673 feet did not drill as fast as the upper and lower sands and may be interpreted as a shaly sand. This interpretation is supported by the potential curve of the electric log.

In Figure 18-2 are two curves plotted from the data on the drilling-time chart of Figure 18-1, using the normal scale for correlation on the left and the enlarged detail scale for lithologic interpretation on the right. A close comparison of the detailed curve with the potential curve in Figure 18-1 reveals not only the corresponding sand sections but also a close resemblance between the patterns of the two curves. Note, for example, such minor features as the slightly sandy shale streaks at 3666 feet and 3691 feet, which are represented as slight bulges in the potential curve. The characteristics of electric and drilling-time curves are determined by changes in lithology. The drilling-time break at 3676 feet is interpreted as anomalous to lithology because a connection was made at this depth and part of this foot was drilled with the clutch out, causing an erroneously timed foot to be registered. By marking on the log where interruptions in drilling occur, such features may be recognized with ease and incorrect interpretations prevented.

The curves of Figure 18-3 which were plotted from the same data as those of Figure 18-2, show by solid lines the loss of detail in using five-foot intervals instead of one-foot intervals and by dotted lines the effect of averaging when using drilling-rate values. In the upper solid curve on the correlation scale the total time for five feet was used and plotted as a bar curve according to the manner generally practiced on sample logs. In the lower solid curve on the detailed scale, the average time per foot was plotted as a point-to-point curve. In both of these curves the presence of two sands and one shaly sand is observed, but the exact depths at which they occur, their net thickness, and minor lithologic breaks are absent. Obviously, it requires more time to plot the curves in Figure 18-2 than in Figure 18-3, and the information to be gained is disproportionate to the time saved. There is some value in large-interval drilling time and in drilling-rate curves to be sure, but their use is restricted to problems where only general impressions are needed either for correlation or lithologic interpretation. In plotting sample logs on the basis of percentage of lithologic types present in each sample, the position of major breaks may be determined by plotting a drilling-rate curve similar to the upper dotted curve in Figure 18-3. Where difficult full-length correlation problems are encountered, however, the drilling-time curves of Figure 18-2 will be found far more reliable and useful. Drilling-rate logs are useful in sample examination work in determining sample lag, but here again the information is only exact within the limits of accuracy of the method used. Further discussion of the application of drilling time and drilling rate follows at the end of the next section.

Several devices purport to record changes in rate of penetration in terms of feet per hour, and mechanical instruments have been marketed that provide drilling-time logs or data from which these logs may be plotted manually. One of the drawbacks to the use of drilling-time logs has been the time required to plot curves of the type illustrated in Figure 18-2. There is no machine available that will reliably record or plot drilling-time logs of this type and eliminate human errors. Considerable experimental work along this line has been done, and the need for such a device is great.



x — Connection

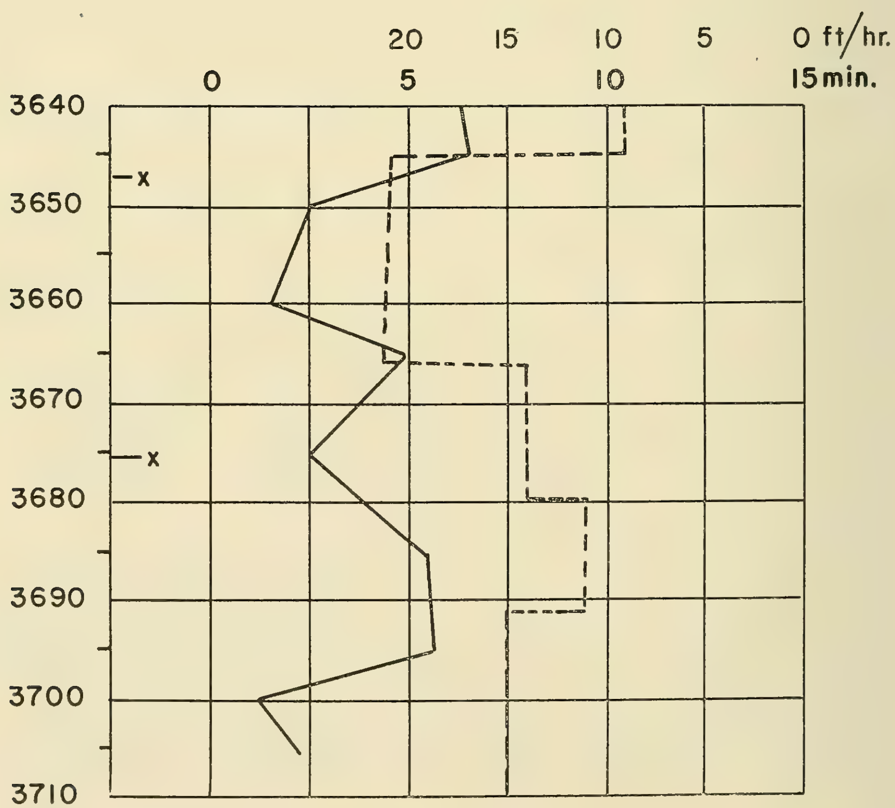


FIGURE 18-3. Curves plotted from same data as those of Figure 18-2. Solid line represents a plotted five-foot interval. Dotted line reflects an average plot.

APPLICATION OF DRILLING-TIME LOGS

Many of the uses for drilling-time logs have been cited and illustrated in the literature. The value to drillers, contractors, and operators is well known. The chief concern is the drilling of the greatest amount of hole in the shortest time possible consistent with good safety practices. At the same time anyone connected with the drilling of an oil well knows that the purpose of drilling a hole is to gain information, the use of which may lead to production of oil or gas. The contractor may find drilling-time records most useful in the analysis of operations and the study of down time as well as pay time. The performance of different types of bits in various formations can be observed directly on drilling-time charts which reflect the types of formations being penetrated. The driller finds drilling-time charts of value as a record of his tour showing exactly how much he drilled, what type of formations were encountered and their depths, and a record of time down for sundry purposes. The guess work is eliminated. But the driller, like the operator, is concerned with finding oil and he knows that reservoir beds are porous media overlain by hard or impervious layers. If he knows he is drilling in a section where potentially productive formations may occur and has not been given precise instructions in respect to coring, logging, or testing, the driller uses his best judgment in the interest of the operator. When he observes a drilling-time break, he may stop drilling and circulate samples for examination and wait for orders before drilling past any formation that might carry oil or gas. The drilling-time charts provide an indisputable record of where the top of the break was encountered and how many feet have been drilled in it.

The geologic importance of drilling-time logs is evident primarily in the fact that foot-by-foot information is available for correlation. As has been shown in Figures 18-1 and 18-2, a drilling-time log, plotted on a time scale such that the amplitude between fast and slow peaks generally corresponds to the range between the shale base line and the maximum peak of an electric-potential curve, provides the geologist with data that may be used, within reasonable limits, for much the same purposes as an electric log itself. It is obvious, therefore, that if a drilling-time log of a well corresponds in pattern to an electric-potential log of that well after the hole has been drilled, the drilling-time log made during the drilling could be used for the purposes served by the electric log. This has proved true particularly in the Gulf Coast area where long-range or local correlation is based on the succession of a series of beds predominantly shale and sandstone. The stratigraphic position of any portion of a drilling well can be established in advance of electric logging by observing the sequence of beds penetrated as revealed by a drilling-time log.

It would be easy, for example, for the sequence of beds illustrated in Figure 18-2 to correspond to a similar sequence of beds above or below the portion of the well shown. It would be difficult, if not beyond the realm of possibility, for the full length of section drilled and logged, below that depth at which drilling time becomes diagnostic of lithology, to correspond and be correlated erroneously with the same stratigraphic section of another well where such correlation could otherwise be established.

The economic and geologic value of this use of drilling-time logs is apparent. In the writer's experience many preliminary correlation runs of electric logs have been unnecessary because the purpose for which they would have been run was adequately served by drilling-time logs plotted as the drilling took place.

The most widely recognized geologic use of drilling time is in connection with coring operations. Careful recording aids in obtaining accuracy in well measurements, particularly where continuous coring is done over a long section. Drilling time often makes it possible to interpret the lithology of missing portions of cores recovered and identifies the portion of section cored from which the recovered core came.

Unless 100 percent of the core is recovered, it may be difficult to determine the net thickness of productive formations, even with the aid of an electric or radioactivity log. In areas where limestone streaks are interbedded with saturated sandstone, as in the Oligocene formations of south-central Louisana, it is nearly impossible to interpret an electric log correctly without corroborative data. Greatest accuracy may be obtained in such problems by the use of electric logs, drilling-time logs, and cores combined.

Another important use of drilling-time data is their aid in the interpretation of elecric logs. It is common practice in drilling wells in the Gulf Coast area to rely on sidewall cores to check questionable shows of saturation in beds not cored during the drilling. Some of these questionable shows are thin calcareous beds which produce resistivity kicks on electric logs that are not unlike those that might be caused by saturated sandstones. The detailed examination of an electric log in conjunction with an accurate drilling-time log may reveal information on these questionable beds sufficient to identify them as calcareous or arenaceous. This use of drilling-time logs reduces the cost of sidewall coring and effects a further saving of rig time.

The use of drilling-time logs as an aid in the interpretation of electric logs may be applied to the problem of reserves estimate. Estimates of ultimate reserves of oil and gas often fail to represent the actual amount of eventual recovery. Although great progress has been made in understanding physical and chemical reservoir conditions and factors relating to the recovery of petroleum resources, the amount of reserves in place is given only as an estimate. Some even discount the value of making estimates of this character because of the lack of knowledge or possession of empirical data necessary to arrive at reliable conclusions. Efforts are continuously being made to increase the accuracy of reserves estimates. The oil or gas content of a reservoir bed is generally given in barrels of oil or mcf. of gas per acre foot. Lack of adequate knowledge pertaining to the reservoir conditions limits the accuracy of the estimate of the formation's content per unit volume, but the factor given is the best available in light of present-day scientific understanding. An estimate of the areal extent of a reservoir bed is also subject to considerable latitude because of the lack of knowledge concerning migration channels and underground drainage conditions. The estimate again is made on the best information that can be supplied by the subsurface geologist after mapping the structure in which the producing horizon is found.

In establishing the net effective thickness of the reservoir bed, there is a greater means of eliminating the necessity of an estimate, provided adequate data are available. In a section where reservoir beds are very uniform in respect to lithology, porosity, and permeability, the thickness may be determined by the driller's record, an electric log, a radioactivity log, or other reliable methods of logging or observing a formation. In those reservoir beds where the lithology is not uniform all available means may be required to determine the net effective thickness of that bed. Core information and analyses, electric and radioactivity logs, and drilling-time logs contribute to the best possible answer. As shown in Figure 18-1, the less-permeable character of the bed from 3669 feet to 3673 feet was indicated both by drilling-time and electric logs.

There are many cases where thin shale breaks in a sandstone reservoir or tight calcareous streaks interbedded with saturated sandstone are not indicated on electric or radioactivity logs. If recorded on a short enough depth interval, however, drilling time will seldom fail to disclose the presence and thickness of such breaks. The writer has used drilling time recorded at intervals of one-tenth of a foot in a productive section where many and very thin impervious streaks were present and only by this means was able to determine the exact net effective thickness of the reservoir. Therefore, if positive information can be gained as to the thickness of a formation, one of the three essential data making up a reserves estimate can be assigned a fixed value, and the accuracy of the final answer is increased.

Perhaps the greatest argument for the use of drilling-time logs is their value as insurance against the loss of geologic information in the event that other types of logging are precluded because of well conditions or in case of a junked hole. Because a drilling-time log provides essential data corresponding to an electric-potential log, it can be used for correlation to determine the stratigraphic and structural position of a well which might otherwise remain unknown. It may also reveal the presence of probable porous beds that may be saturated because of their structural position, and therefore the economic risk of drilling a new hole or abandoning a location may be substantially reduced.

Since the publication of the first edition of this symposium, the writer has received communication from J. A. Simons, geologist with Creole Petroleum Corporation, regarding the use of drilling-time and drilling-rate curves in Venezuela. He states, "This technique (drilling-time logging) is extremely useful

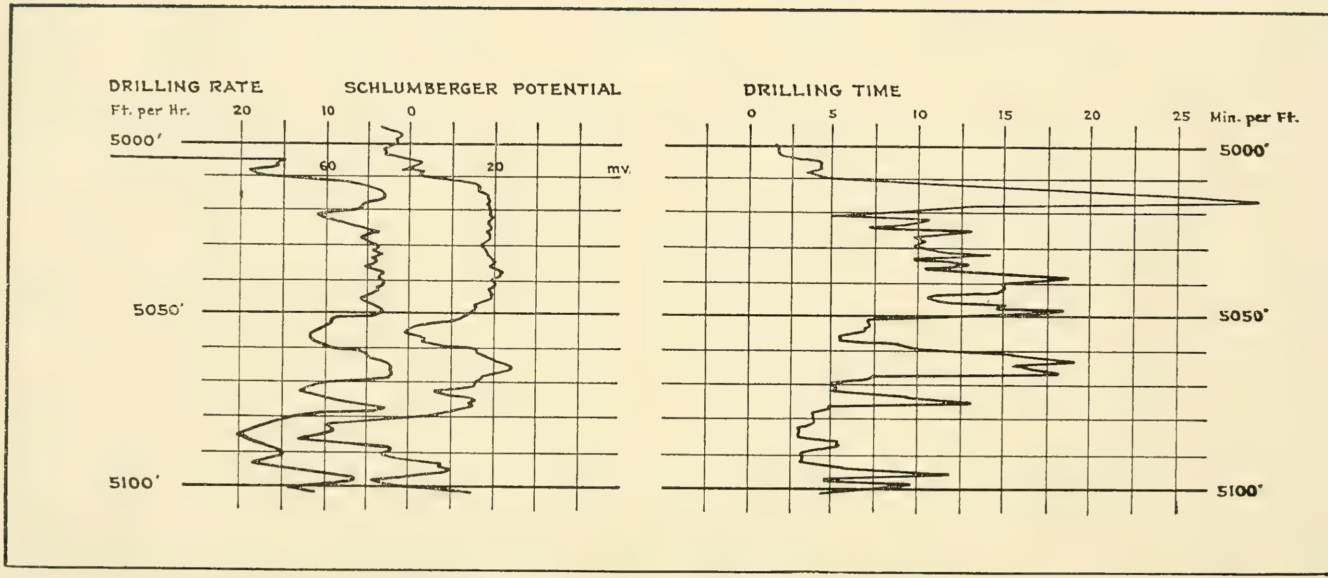


FIGURE 18-4. Correlation of the electrical (SP) curve (center) with a drilling-time log (right) and its reciprocal log in semilogarithmic form, drilling-rate log (left). Data from Creole Petroleum Corporation's No. 2-PSX, Pedernales District, Venezuela. (J. A. Simons.)

in this area (Pedernales District) and is used as a method of bottoming a field well at the base of a known productive sand lens and to prevent the penetration of the next lens, known to be salt-water bearing . . . It developed that the plotting of drilling time in minutes per foot had been tried and poor results were obtained. A different method of plotting—feet per hour per one foot—was tried and has been adopted as a standard practice."

Simons states further, "If it requires a certain number of minutes to drill one foot, that is the drilling time for that foot. But that foot was also drilled at a certain *rate* which can be expressed in units of depth per units of time . . . When drilling time is plotted in feet per hour for one-foot intervals, a semi-logarithmic form of curve is obtained which dampens the effect of very slow feet caused by harder streaks or by the inattention of the driller, and which conversely exaggerates the effect of fast drilling that cannot be caused by anything but the bit entering a zone of easier digging. The scale is chosen to fit the fastest drilling observed, and fluctuations in the hardness of shale do not cause a widely varying curve, and the S.P. log in the shale section is more closely approximated."

The above discussion is illustrated in Figure 18-4 and is introduced in this chapter as an illustration of individual adoption of variations in selection of scale and method of plotting. It should be pointed out, however, that drilling-rate values cannot be determined without first measuring drilling-time values and it would appear that calculating the reciprocal values is an unnecessary step. The use of the zero base line at the right and the plotting of reciprocal values, even on a straight arithmetic basis, might have advantages in the analysis of special problems.

METHOD OF PREPARING DRILLING-TIME LOGS

The experience of the writer in the use of drilling-time data has been based on records obtained from geolograph charts for the most part. Although there are other means by which usable data may be collected, perhaps the most practical source of complete drilling-time records is the geolograph. For this reason it is considered in place here to describe in detail the technique recommended in translating the orginal record into the drilling-time log for which multiple uses have been described.

It is unnecessary to include the maintenance of the equipment, which is the responsibility of the service company. A few points should be kept in mind, however, by the geologist desiring to obtain as perfect records as possible. A drilling-time log is the plotted curve of two components, time and depth, each requiring accuracy within the limits of observational errors. The geolograph machine provides two inking pens, generally supplied with inks of different colors. One pen indicates by vertical and horizontal lines the amount of time that drilling is in progress and when it has been stopped or when the bit is off

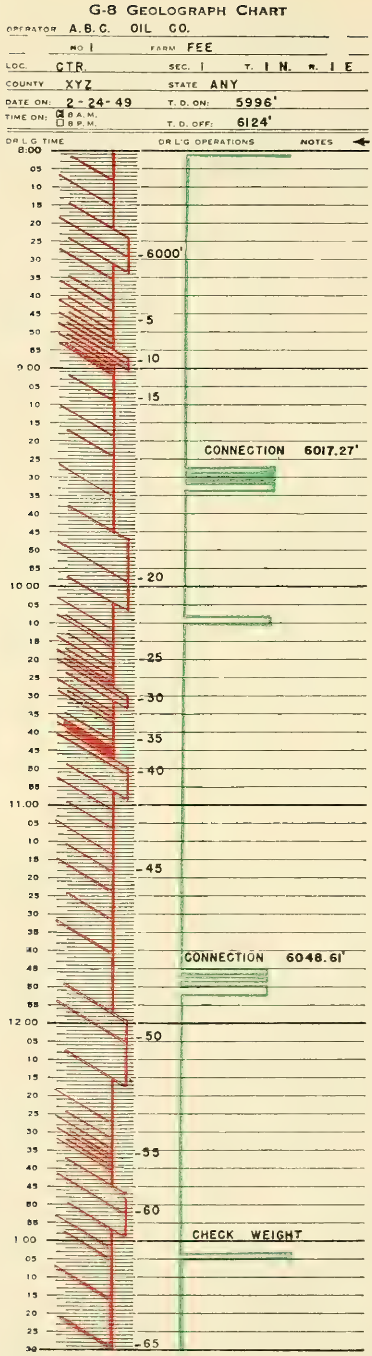


PLATE 18-I. Geolograph chart showing essential data used in preparing a drilling-time log. Displacement of red line to right marks every 10 feet of section penetrated.

bottom. The other indicates by a slanting stroke the completion of exactly one foot drilled, or two feet if set for recording on two-foot intervals. Therefore, the exact depth marked by each stroke of the pen must be known and the length of time occupied in the drilling must be determined. Plate 18-I is a geolograph chart showing essential data used in making a drilling-time log.

It is strongly recommended that the geologist using complete drilling-time data keep his own pipe tally. Practices differ among contractors in keeping pipe tallies, but inasmuch as the object here is to know the depth indicated by each mark on the chart, the geologist's tally must show all pipe in the hole at the time the mark is made. This becomes most important when changes in the drilling string are made, as for coring. The tally should show first the bit, subs, and drill collars in the string, followed by each joint of drill pipe added. The kelly should be measured accurately and its length recorded. The geologist should also observe whether it is the practice of the driller to drill the kelly down or make his connections with some length up on the kelly. The geolograph automatically shows when a new joint of pipe is added, and the geologist should write on the chart the kelly-down depth of each connection, accurate to the nearest hundredth of a foot, as shown on his pipe tally. (See connections at 6017.27 feet and 6048.61 feet in pl. 18-I.)

The charts are generally changed twice a day and when received for translating will show the date, time of chart change, depth of beginning and end of each chart, and correct depth at each connection or beginning of a round trip. The depth of each mark or every fifth mark between connections should then be written on the chart, as 6000 feet, 6005 feet, 6010 feet, et seq., Plate 18-I. If the drillers have been very careful in throwing in the clutch at the proper time, the number of marks should be identical with the number of feet drilled. Often this is not the case, and observation of drilling operations and experience with how such discrepancies occur will show the geologist where errors take place. The most common error of this type is made by the driller in failing to throw in the clutch after making a connection at exactly the same depth as when it was thrown out prior to making the connection. Changes in drilling weight caused by settling out of rock cuttings may cause what might be called "false drilling" or the redrilling of depth without drilling a new formation. Or, if the driller fails to throw in the clutch as soon as the bit reaches bottom with the same weight as when it left bottom, some new hole may be drilled without being recorded. (See 3676 feet in figs. 18-1, 18-2.) Errors of these kinds are readily understood when one realizes that the drilling crew is most busily occupied when connections are made. Often the correction for depth will be made immediately after a connection, but the geologist must use his best judgment in making all corrections so that when a depth is assigned to a mark it will be correct.

Operator A. B. C. Oil Co.
Well No. 1 Fee
Field Wildcat
Parish XYZ County, Any State

60.01	4.50		51	12.50	
02	4.25		52	12.00	
03	6.00		53	4.50	
04	2.75		54	2.50	
05	3.00		55	1.50	
06	2.25		56	1.00	
07	1.75		57	2.00	
08	2.00		58	.75	
09	1.00		59	4.25	
10	1.25		60	5.25	
11	1.50		61	6.50	
12	1.25		62	5.50	
13	1.00		63	2.00	Interruption
14	1.00		64	11.00	
15	7.50		65	13.25	
16	10.00		66	10.00	
17	5.50		67	7.75	
18	4.50	Connection 6017.27'	68	5.00	
19	9.50		69	3.00	
20	11.50		70	1.00	
21	7.75		71	1.75	
22	5.25	Interruption	72	1.25	
23	3.00		73	2.25	
24	1.00		74	2.00	
25	3.50		75	2.50	
26	2.75		76	3.50	
27	1.75		77	2.75	
28	2.00		78	3.00	
29	.75		79	3.50	Connection 6079.04'
30	1.50		80	3.75	
31	2.50		81	8.25	
32	3.00		82	4.00	
33	1.50		83	7.25	
34	1.50		84	3.00	
35	5.00		85	3.25	
36	1.50		86	3.00	
37	1.00		87	3.50	
38	.75		88	4.25	
39	1.25		89	7.00	
40	1.50		90	9.25	
41	7.25		91	10.50	
42	5.25		92	9.25	
43	5.00		93	12.75	
44	6.50		94	6.00	
45	5.50		95	6.00	
46	5.50		96	6.25	
47	8.25		97	5.25	
48	9.00		98	7.75	
49	8.50	Connection 6048.61'	99	10.50	
50	6.00		6100	14.50	

Date Record Feb. 24, 1949
Drilling Notes Bit No. 12 Type .... Mud Weight 9.6 lbs. Viscosity 38"

Remarks Depths off 1 ft. 6063-6080' due to pick up and creep.

FIGURE 18-5. Drilling-time record.

Where no "extra" marks have been made and no "skips" noticed, there may accumulate fractional-foot errors, which may be designated as "creep." Over long-continued drilling, involving several connections or even round trips, a correction may be required, and it is difficult to know where it should be made. Having written the kelly-down depth at each connection and the correct depth at a round trip, accurate in each case to the nearest hundredth of a foot, it will be obvious what depth should be assigned just before or just after making a connection. For example, if a connection has been made at 6079.04 feet in Figure 18-5 and a foot mark is shown immediately after the connection, it would be reasonable to indicate the depth of the mark prior to the connection as 6078 feet, as the total number of feet drilled corresponds to the number of foot marks on the chart. Had the connection been made at 6078.97 feet, however, and a foot mark shown just prior to making the connection, with a normal drilling interval following the connection before the next foot mark was recorded, it would be reasonable to assign a depth of 6079 feet to the foot mark prior to the connection. Apparent errors of this type would be the result of "creep."

The foregoing is only suggestive of some generalizations that may be made in preparing the chart for time determinations. Frequent use of drilling-time charts will increase the speed and accuracy in obtaining proper depth designations. The chart reproduced in Plate 18-I provides 24 inches for recording twelve hours of time, or two inches per hour. The hour is divided into twelve divisions of five minutes each, and these are further divided into one-minute divisions. For high speed, when the requirements demand it at the sacrifice of accuracy, the eye can measure the distance between foot marks within an accuracy of approximately twenty to thirty percent. Many uses of drilling-time logs require greater accuracy than this, however, particularly when minor breaks in the over-all pattern are used to correlate with minor breaks on an electric-potential log. To obtain greater accuracy, with an error of less than one percent, measurements may be made with an engineer's scale, using the thirty-divisions-per-inch scale for the purpose. This scale, placed on the chart having two inches per hour, will provide sixty divisions per hour or one per minute.

The use of a printed form to tabulate the time readings may be considered as an extra step, and some may suggest plotting directly from observation of the chart. It has been found that this extra step not only avoids many errors that might otherwise be made but actually saves time. In addition one often wishes to plot the same data on more than one scale, in which case the time saving is considerable. The same person may make the readings and write the tabulation, but if one person keeps his eye on the scale and chart and another writes down the time on the form, it will save two-thirds of the time required for this operation. Additional time can be saved in the following step, plotting the log from the tabluation, by having one person read the units off as another plots the coordinates. Figure 18-5 illustrates a type of form on which drilling-time data may be tabulated.

Determination of the time factor from the chart, using the engineer's scale, is made by placing the scale parallel with the long dimension of the chart and at the left of the base line from which the slanting stroke is made. The zero of the scale is then placed at the top side of the depth stroke and the position of the top side of the succeeding depth stroke noted on the scale. The observer can read the scale to the nearest quarter of a division or fifteen seconds of time, and this reading is the time factor for the foot being measured. Because of the type of coordinate paper recommended for plotting the log, it will facilitate recording and plotting these time factors if decimals instead of fractions are used, as in Figure 18-5.

No difficulty will be encountered in reading and tabulating the time where there have been no interruptions in drilling. If drilling has been stopped at other than at the completion of an even foot, as at 6021-6022 feet in Plate 18-I, the time out must be subtracted from the total time to indicate only the net time consumed in the drilling of the foot. The position of the 6022-foot stroke on the scale is shifted to the top of the bottom horizontal line, indicating the end of the time out. The position on the scale of the top side of the top horizontal time-out line will be the net total time required in the drilling of this foot. If more than one interruption has been made in the drilling of one foot, this process is repeated for each pair of horizontal lines indicating interruptions. All interruptions should be recorded on the tabulation, as in Figure 18-5, and by conventional symbols shown on the plotted log, as in Figure 18-6, to prevent false interpretations. Care should be given to the pens so that they are in exact horizontal registry in respect to each other at the top of each chart; otherwise, errors in calculating time-out intervals may be made.

After the chart has been prepared with the proper depths indicated, any instructed person may make the time determinations and plot the log. Office clerical assistance is used often by geologists supervising the work on several wells being drilled at the same time. When this is done, it is imperative that the original charts be received with the correct depth designations shown.

Plotting the log starts with the tabulation of data as in Figure 18-5. The selection of the time scale is important and has been discussed and illustrated in previous papers by the writer. The log strip found to be most satisfactory for interpretative work consists of coordinate paper with twenty divisions per inch and cut six to eight inches in width. The heading at the top should show the name and location of the well, datum elevations, and the vertical scale used. The name of the observer or plotter may be useful for the record. Referring to Figure 18-6, the depths are given at the left edge of the log at intervals of 10, 25, 50, or 100 feet as determined by the vertical scale used. The time scale is shown across the top of the log in terms of minutes per foot.

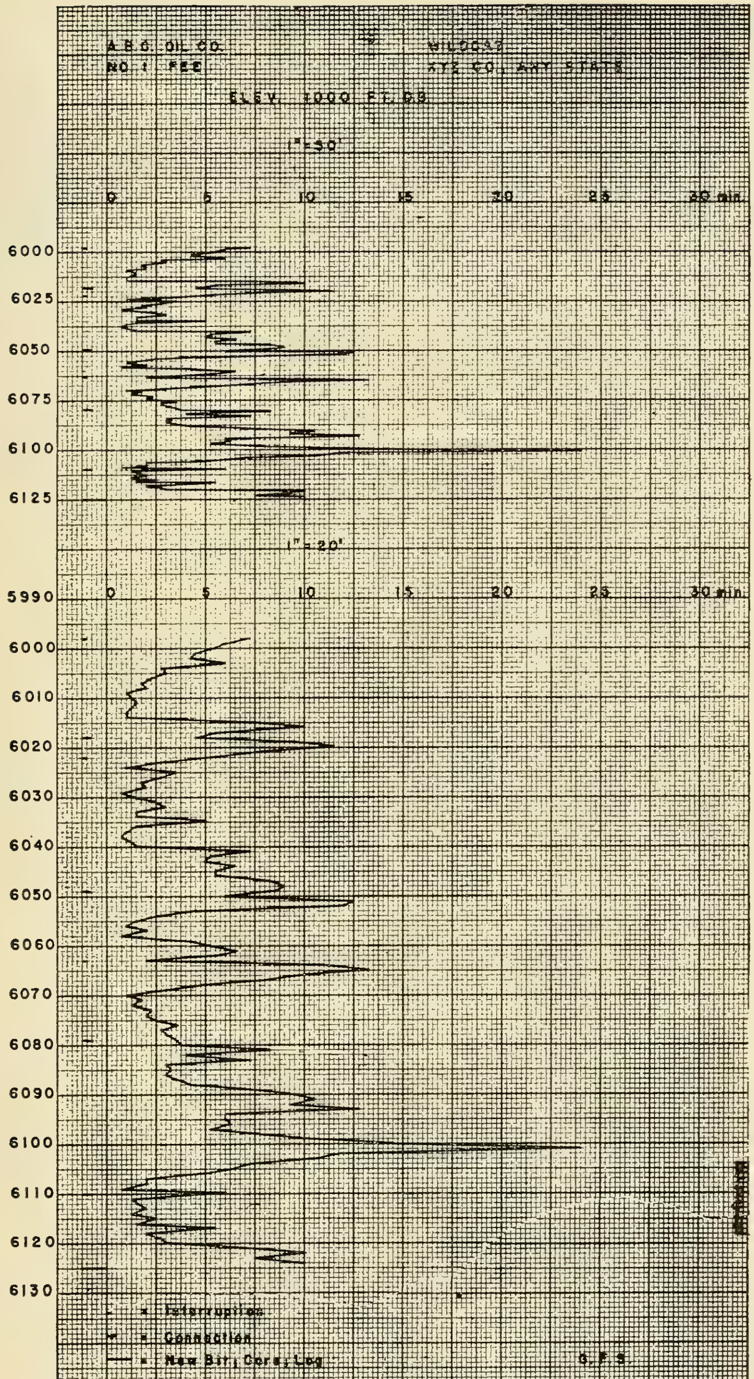


FIGURE 18-6. Drilling-time log strip.

Sometimes the upper part of a well may be drilled at such a rate that two-foot timing is desirable. In this case the horizontal or time scale will be one-half that for one-foot timing so that the relative amplitude of the curves will remain the same. The time scale should be given on the log when changing from two-foot to one-foot recording. It has been found by experience that a time scale of five minutes per inch on one-foot recording is most acceptable to yield an amplitude corresponding to electric-potential curves. On this scale each unit represents a quarter of a minute, which is the base unit tabulated in Figure 18-5. If conditions in an area are such that drilling is much faster or much slower than normal, the time scale may be changed to meet the requirements of that area. It may be preferable, where drilling rates are very slow, to shift the base line instead of changing the time scale. In either manner of plotting the log, exceptionally slow feet will be encountered which will exceed the visible scale on the log. Such off-scale footage may be plotted on scale using the thirty-minute time as the zero base and cross-hatching the off-scale portion for convenience. The resulting log will appear similar to off-scale electric-resistivity logs.

The question may arise as to what to do with apparent errors in time values. If during continuous drilling, the brake is set while the driller is busy elsewhere, the weight may drill off the bit before the drill stem is lowered. This often occurs in drilling soft formations, and the geolograph will fail to record the true net time required in the drilling. It is recommended that the values be plotted as they actually are recorded even when they are known to be fictional. The reason for this is that, if an effort is made to make arbitrary corrections, the value selected may have as little relation to the correct value as the recorded value. Therefore, if all values are plotted as recorded, the correction can be made in the interpretative phase of the work. One very fast foot in the midst of normally slow drilling, or one very slow foot in the midst of normally fast drilling would present no problem in its interpretation. The writer has followed this practice consistently because sometimes an apparent time error may not be an error at all, but rather may represent a very abrupt lithologic change over a short distance. A thin streak of shale in a soft sandstone, an ironstone bed located in soft shaly sand, or a thin streak of soft sandstone interbedded with a very hard limestone would appear as false recordings such as are indicated above.

As a suggestion, there are many advantages to be gained from plotting the log with black ink rather than with pencil. The tabulated values are plotted as coordinates on the log with respect to depth and time. A sharp, medium-hard pencil is ideal for this purpose. These points may then be connected by an ink line, using a ruling pen and metal-edged ruler. The inked curve is much easier to examine than a penciled curve, particularly under poor lighting conditions. An inked curve is preferable to a penciled curve also because it facilitates reproduction by direct printing or photostating.

In conclusion, it may be suggested that the free exchange of drilling-time logs would prove of considerable mutual benefit to geologists in much the same way that the interchange of electric and radioactivity logs is at the present time. Many companies publish catalogs of logs available for distribution. If drilling-time logs were added to these lists, they would benefit geologists whose responsibility it is to interpret properly the records made in the drilling of a test for oil or gas.

Reprinted from *Subsurface Geologic Methods,* 1951, p. 455-475.

Chapter 19

DIPMETER SURVEYS

E. F. Stratton
and
R. G. Hamilton

The SP (spontaneous-potential) dipmeter was described in 1943 by H. G. Doll as a means for determining the direction and magnitude of formation dip *in situ*. This instrument was designed to record simultaneously three SP curves of known orientation, 120° apart along three generatrices of a well bore. Each curve fixes thus one point on a bedding surface and the position of the surface can be determined (fig. 19-1) by the displacement between the curves.

It was thought desirable in some areas to record 3 resistivity curves instead of 3 SP curves. Accordingly, the design and development of a resistivity dipmeter was undertaken. The availability of a resistivity dipmeter, in addition to the SP dipmeter, has extended appreciably the application of the procedure. Some 6 or 7 thousand dipmeter levels, SP and resistivity, now have been recorded in wells throughout most of the major oil provinces in the country and in many foreign fields. It seems advisable to analyze these data and to describe their application to some of the problems that have been encountered in exploration and development work.

The hole assembly, about 25 feet long, consists of a mandril to which are attached three hard-rubber arms spaced 120° apart; in the center of each arm and positioned on the same plane at right angles to the axis of the instrument is one of the three recording electrodes. Attached to the electrode unit is a photoclinometer, which determines photographically the orientation of each of the

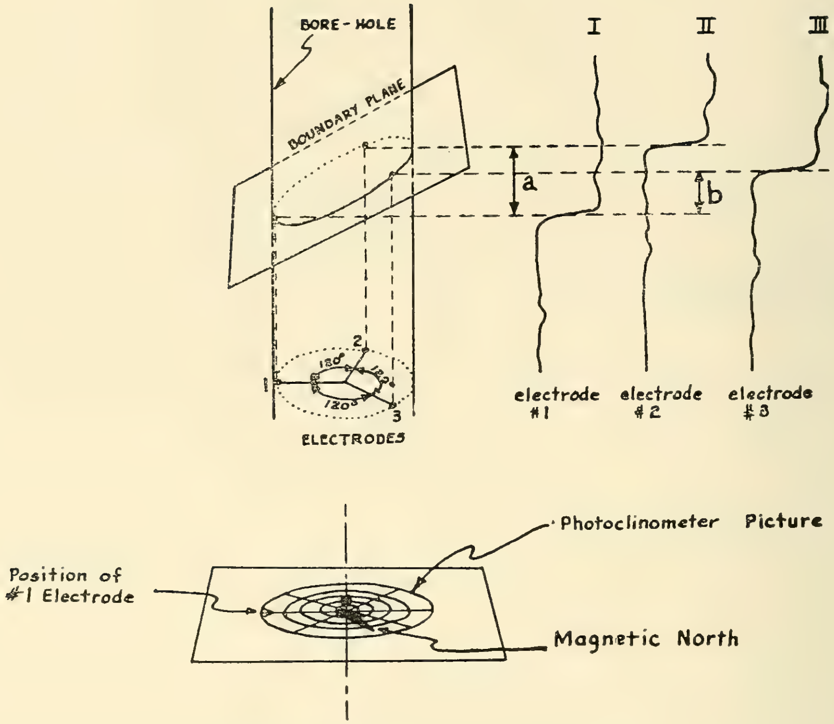


FIGURE 19-1. Basic principles of dipmeter.

three SP or resistivity curves and gives the drift and azimuth of the well bore. Spring guides above and below the photoclinometer-electrode assembly serve to keep the device centered in the hole and to prevent it from turning.

The curves are recorded photographically at the surface on the standard electric-logging recorder.

AREAS OF APPLICATION Those regions where the geologic section is primarily sand and shale, i.e., California or the Gulf Coast, are best suited for the use of the SP dipmeter. The spontaneous potential here in general shows sharp, well-defined anomalies at formation boundaries, which give definite dip determinations. Likewise in these areas a series of bedding surfaces between sand and shale can usually be found at any depth in a well where a dip determination is needed.

The resistivity dipmeter, on the other hand, has proved of utility in such areas as west Texas, the Mid-continent, and the Rocky Mountains. The numerous resistivity anomalies between, for example, shale and limestone found in most wells in these areas provide satisfactory levels for dip determinations at almost any position in a well.

FIELD PROCEDURE

Dipmeter surveys are made with the same cable and, as noted above, surface-recording equipment used for electric logging. Common practice is to make the dipmeter run immediately after the electric logging.

The dipmeter levels must be chosen from the electric log. The assembly—electrodes, photoclinometer, and spring guides—is lowered to the base of the shallowest level and a photoclinometer picture taken. This picture determines the orientation of the electrodes and the curves, as well as the drift and azimuth of the well bore at the base of the level. The curves are recorded to the top of the level, and a second photoclinometer picture is taken. The latter gives the orientation of the electrodes and the curves, as well as the drift and azimuth of the well bore at the top of the level. After this step, the assembly is lowered to the base of the second-shallowest level, and the procedure given above is repeated. Other levels are recorded in the same manner.

After the deepest level has been recorded, it is resurveyed with a photoclinometer picture taken in the middle of the level as well as at the top and base. Each of the higher levels, similarly, is repeated as the equipment is withdrawn from the hole.

INTERPRETATION

All dipmeter surveys are analyzed by a staff specializing in such work, and two independent interpretations are made for each operation. Likewise, the data from the original and check runs on each level, generally recorded with different electrode orientations, must agree, or the results are discarded. After the orientation of the curves, their displacement, and the drift and azimuth of the well bore have been determined over the interval of a level, the magnitude and direction of the dip are obtained quickly by mechanical means.

A typical computation sheet is shown in Figure 19-2. The first column designates the level; AA1, for example, is the original run, AA2, the check run, etc. The second column gives the depth interval of the level. The third column shows the azimuth of the well in degrees from magnetic north; the fourth column the drift angle. The fifth column is the position of the No. 1 recording electrode in degrees from magnetic north. The sixth and seventh columns indicate the displacement in inches of curves recorded on electrodes two and three with respect to the No. 1 curve. The last three columns give the amount and direction of the dip computed from the previous data.

STATION	Depth Interval	From Magnetic North			Displacement of Curves in reference to I.		DIP			OBSERVATIONS
		Drift Azimuth	Drift Angle	Orient. No. I	II	III	Dip Angle	Direction from Magn. N	Direction from True North	
AA1	1645 1659 to	36	1 00	92	Uncertain					
AA2	1653 1673	36	1 00	97	Uncertain					
BB1	2000 2020 to	342	0 45	77	U 0.4	U 1.2	9	120	S 50 E	
BB2	2004 2024	342	0 45	77	U 0.4	U 1.2	9	120	S 50 E	
CC1	2856 to	234	2 00	229	D 0.6	D 2.2	17	91	S 79 E	
CC2	2875	234	2 00	16	D 0.8	U 1.2	15	93	S 77 E	
DD1	3135 to	241	1 00	119	U 1.8	U 0.6	13	75	N 85 E	
DD2	3158	241	1 00	299	D 1.9	D 0.9	13	81	S 89 E	
EE1	3520 to	237	2 00	214	-0-	D 1.8	15	88	S 82 E	
EE2	3535	237	2 00	75	U 1.2	U 2.0	15	94	S 76 E	
FF1	3608 to	238	2 15	292	D 0.8	D 2.2	14	140	S 30 E	
FF2	3622	238	2 15	292	D 0.8	D 2.2	14	140	S 30 E	
GG1	3844 to	242	2 00	265	D 2.0	D 1.2	15	60	N 70 E	
GG2	3870	242	2 00	355	D 0.5	U 1.6	16	66	N 76 E	
HH1	3990 to	242	2 15	312	D 2.0	-0-	17	66	N 76 E	
HH2	4000	242	2 15	195	-0-	D 2.2	17	72	N 82 E	
II1	4155 4183 to	234	1 30	343	D 2.3	D 2.3	26	74	N 84 E	
II2	4151 4173	234	1 30	343	D 2.3	U 1.6	26	74	N 84 E	
Smith Petroleum Company, T. Henry #3, Run #1, September 1, 1947										

FIGURE 19-2. Typical dipmeter computation sheet.

SELECTION OF LEVELS Widespread experience indicates that the accuracy of a dipmeter survey depends principally upon a careful selection of the zones in a well over which the measurements are made. It is obvious, too, that numerous dip determinations made at relatively close intervals in a well will more clearly define structural and stratigraphic conditions than a few randomly spaced levels.

After it has been decided at what depth positions dip determinations are needed, a zone or level from 25 to 50 feet in length is chosen nearby for recording the three curves. Each level of such length thus provides a number of bedding surfaces on which a dip determination is made; if the dip measurement is made on but one contact surface, a freak dip direction due to minor bedding irregularities might be considered as representing the true formational dip.

It has been found that the most satisfactory zones for a dipmeter level are those consisting of relatively thin beds, 2 or 3 to 10 feet thick, having sharp contacts with adjacent formations. Such zones for a resistivity-dipmeter level are thin limestones or resistive sandstones interbedded with shale, but for an SP-dipmeter level thin sandstones interbedded in shale are more favorable.

Thin shale or sandy shale beds, on the other hand, within thick sand sections and thin shale beds or minor resistivity variations within a massive limestone frequently give erratic dip results. Sometimes, too, dipmeter measurements at the contact between thick sandstones or limestones and the adjacent shales show abnormal results, although reliable values frequently have been obtained at such contacts.

APPLICATION

Dipmeter surveys provide data assisting in the solution of many structural and stratigraphic problems encountered in exploratory and pool development wells. The correct location of offset wells after one has been drilled is a common problem. If the initial well is a wildcat and a dry hole, it is necessary to know, first, whether the sediments are flat or whether there is some evidence of structure, and, second, what is the direction and amount of dip. Dipmeter surveys have been of considerable help in evaluating structural control in directional-drilling problems and in unraveling structural conditions adjacent to piercement salt domes. They have also played important roles in establishing the stratigraphic relationships above and below unconformity surfaces and have assisted in better interpretations of faults. They have served as control during the interpretation of seismic data and in outlining potential entrapment areas.

Reprinted from *Subsurface Geologic Methods,* 1951, p. 625-630.

Chapter 20

PERMEABILITY SURVEYING METHODS

P. E. Fitzgerald
and
S. J. Martinez

Permeability surveying is practiced commercially in exploratory wells, development wells, and secondary-recovery projects. Its most valuable application is in guiding and evaluating work-over and remedial operations. The service is available to most oil-producing areas in the United States, Canada, and Venezuela.

The term permeability surveying is somewhat of a misnomer. Actually, this type of well surveying results in a graphic profile indicating the relative permeability of each zone in the well. Such permeability determinations, when correlated with core-analysis data, may be used to estimate the absolute permeability in *darcies*.

USES

Permeability-profile surveys are a source of vital information for such work as selective acidizing, selective shooting, plugging for the control of water-oil or gas-oil ratios, or nearly any type of remedial work on wells.

When correlated with other well information such as geological data, core logs, electric logs, and production data, the permeability profile also assists in locating the position of high water- or gas-producing zones. It can be utilized to determine the location, thickness, and relative capacities of various exposed zones to take or produce fluid. The data have proved also of value for well-to-well correlation of permeability zones. When used before and after acidizing or fracturing a well, it indicates those producing sections that have received the most benefit from the well-stimulation operation as well as those needing additional treatment.

The permeability profile is not used directly to determine fluid content of zones or for estimating reserves, but it is helpful in such determinations when integrated with other well data.

Permeability profiles are useful in planning pressure-maintenance programs or evaluating the efficiency of secondary-recovery operations. Surveys conducted on input wells of water-flooding projects assist in determining injection rates and locating by-passed zones.

The surveying techniques followed in obtaining permeability profiles also can be utilized for obtaining other valuable subsurface information such as locating zones of lost circulation in drilling wells, zones of water entry, and casing failures; channeling around faulty casing seats or extending above or below perforations; or controlling and evaluating remedial plug-back operations.

FIGURE 20-1. Exterior view of electric pilot truck showing conductor cable being wound on power-driven reel.

In modified form, permeability surveys can be used to control the application of chemicals in selective-acidizing treatments.

HISTORY

The rapid and widespread use of chemicals in wells to improve their producing characteristics led to the early development of tools and techniques that would assure more efficient and effective use of the chemicals.

One of the problems solved by researchers in well treating was the determination of what part of the exposed section in the well should be treated chemically. This determination led to the development of methods that would insure introduction of the chemicals into the desired zone. One of these methods which utilized a subsurface electrode suspended on an electric cable, indicated at the surface the location of an interface between the treating acid (pumped down the tubing) and oil (pumped down the annulus).

The success of this technique led to its adaptation to other uses. Not long after, the selective acidizing electrode was being utilized to locate and evaluate

FIGURE 20-2. Interior view of electric pilot truck showing control panels and automatic chart recorder.

zones of permeability in a well. It was found that the data obtained could be correlated readily with other types of well data, including core analyses, drill-time logs, temperature surveys, and electric logs.

Thousands of permeability-profile surveys have been made since the commercial introduction of the method in 1941. The experience so obtained has been most helpful in perfecting the technique, improving the instruments (figs. 20-1 and 20-2), and interpreting the data.

METHODS

The four basic methods of determining the comparative permeability of rocks *in situ* at the bottom of a well are classified as:

a. Electric or radioactivity logging
b. Moving-interface surveys
c. Static-interface surveys
d. Fluid-velocity surveys

The moving-interface survey (fig. 20-3) consists of injecting fluid into a well at a given rate, and then following the interface between two dissimilar fluids (fig. 20-4) down the well bore by means of a suitable detection tool

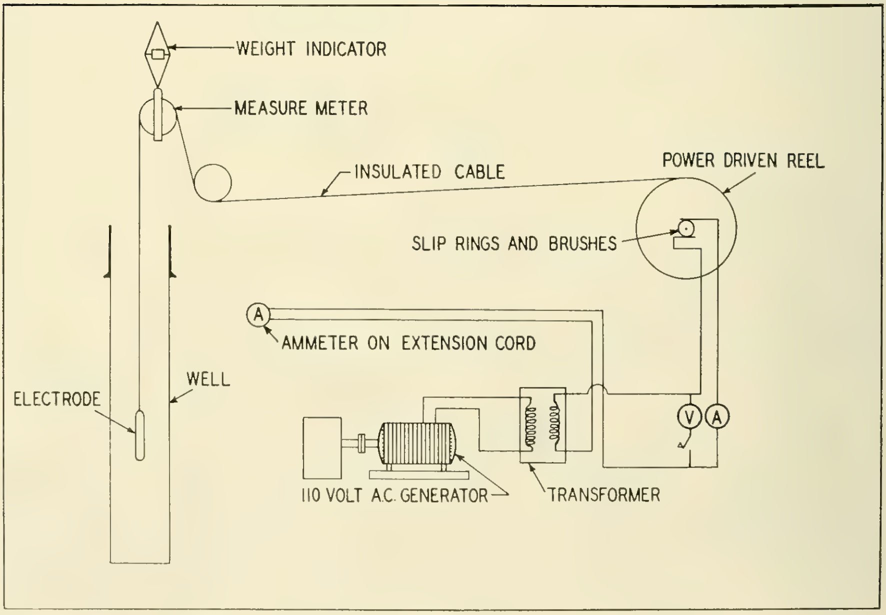


FIGURE 20-3. A schematic diagram showing well hookup for conducting a two-fluid permeability survey.

connected to recording instruments at the surface. The rate of fall of the interface will remain constant until a permeable zone is passed. At this point, the rate of fall of the interface is retarded since part of the injected fluid being used to depress it now is entering the permeable zone just passed by the interface. Each time a permeable zone is passed, the rate of fall is slowed still further, until the bottom of the well is reached, or until a point is reached in the well bore below which the formation will not take fluid.

The flow rate into any given zone is obtained by taking the difference in rate of fall above and below that zone. This value (feet per minute) is converted readily into gallons of flow per minute. Thus, for any given rate of fluid injection at the surface, the proportional quantity of fluid entering each zone may be obtained and the comparative permeability profile determined (fig. 20-5). These data are reliable as long as the diameter of the well bore is uniform. Variations in hole size naturally will cause corresponding changes in fluid velocity. These changes can be determined and corrected for by running a caliper (hole diameter) survey.

Several different surveying procedures have been developed, all of which are based on the principle of following a moving fluid interface. The original technique, still widely used, measures the electrical conductivity of the survey

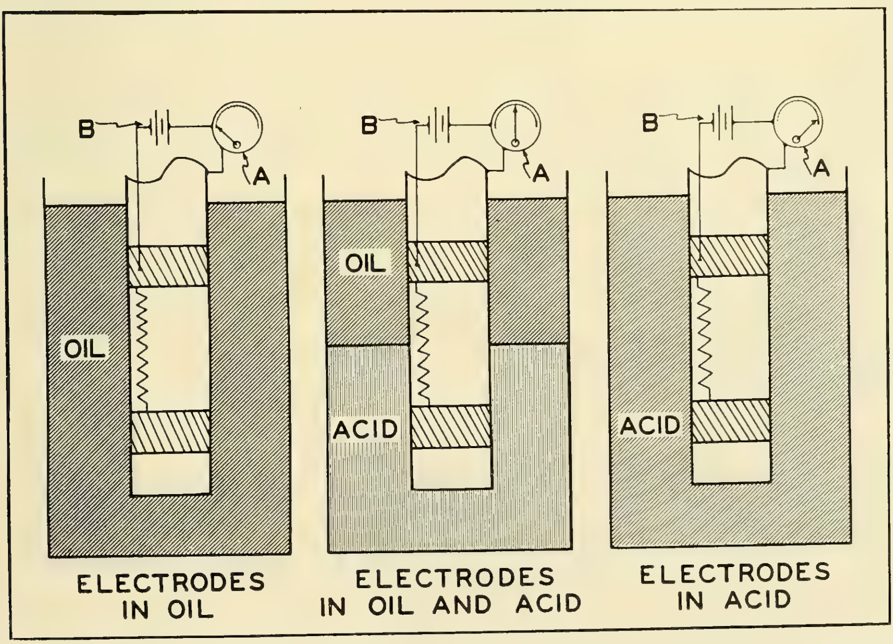


FIGURE 20-4. Detection of an acid-oil interface is based on a measurement of conductivity of external fluid between two insulated electrodes.

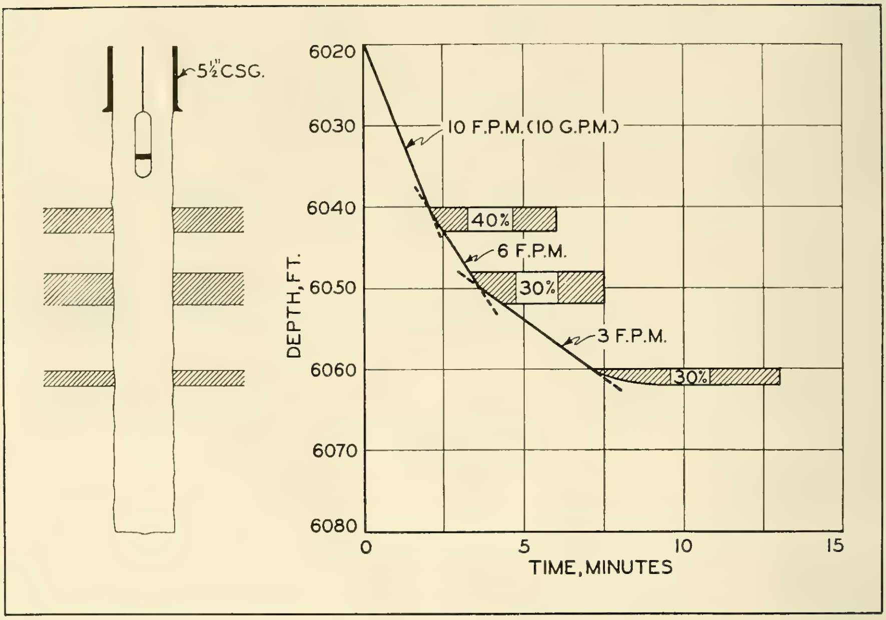


FIGURE 20-5. By following water-oil interface with the electrode while injecting fluid at a constant rate, one can determine relative percentage of fluid accepted by each zone.

fluids. In this instance, a differential interface is obtained between a nonconducting fluid (kerosene, crude oil, etc.) and an electrically conductive fluid (brine, inhibited acid, or fresh water conditioned by dissolved electrolyte). In conducting this type of survey, the well is first filled with the conducting fluid to a point several hundred feet above the casing seat. The nonconducting fluid is then injected at a constant rate, and the location of the interface is established at predetermined intervals, by means of an electrode unit suspended on an insulated, electrically conductive cable attached to control and measurement instruments at the surface. The electrode tool is designed so that it will indicate whether it is immersed in conductive fluid or nonconductive fluid, or whether it is partially immersed in each.

A more recent modification of this method consists of utilizing the interface between a clear fluid (transparent or translucent) and an opaque fluid (usually produced by the addition of a soluble dye). In this instance, the interface detection tool consists of a photoelectric cell assembly which measures the light-transmission properties of the fluid in which it is suspended (fig. 20-6). The surveying procedure is similar to the electrode method described above. The well is filled with clear fluid (usually water), and a section is conditioned with dye, by means of a remote-controlled bailer. Fluid injection is started at the

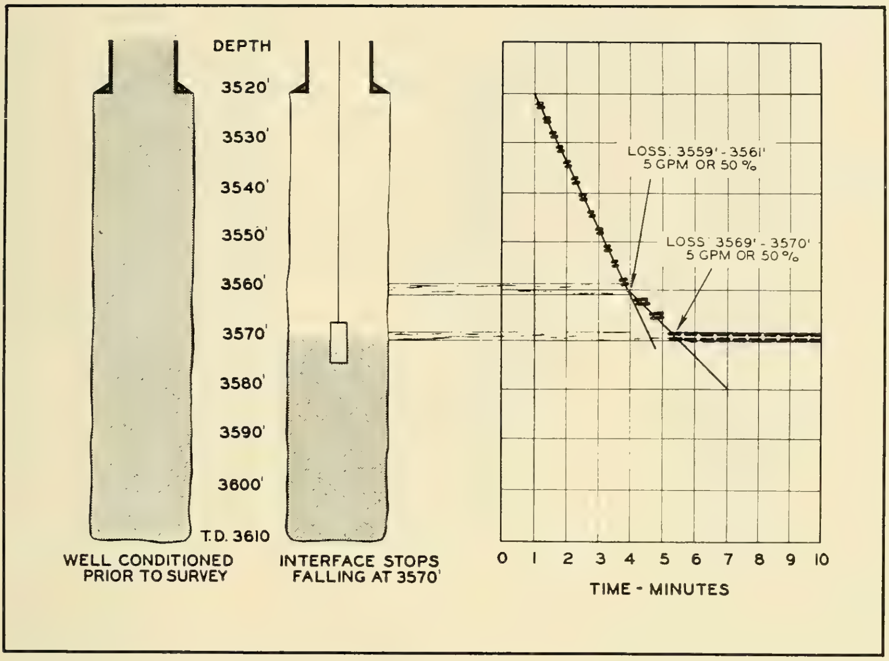


FIGURE 20-6. Photoelectric detection tool is used to follow an interface between fresh water, and water made opaque by addition of a dye.

surface, and the interface is followed down the hole by means of the photoelectric tool. Changes in the rate of fall of the interface indicate fluid loss into the zone being traversed.

Another variation of the moving interface technique is to run the survey in a normal manner while fluid is injected from the surface. The survey then is rerun, and the fluid is injected at the bottom of the well bore through a tubing string and follows the interface upward. This procedure provides not only a comparative permeability profile, but also a log of the volume of the bore hole at any depth interval, thus making a separate caliper survey unnecessary. This method is not widely used because it is more expensive and time-consuming than other methods.

The static-interface method (fig. 20-7) of surveying involves a somewhat different principle in determining the relative proportion of injected fluid that different sections of the formation will accept. This method is largely experimental and has not gained widespread use because of the necessity of running tubing in the hole. It is based on the following principle: when two different fluids (usually fresh water and brine) are injected into a well, one at the bottom through a string of tubing and the other at the top of the formation

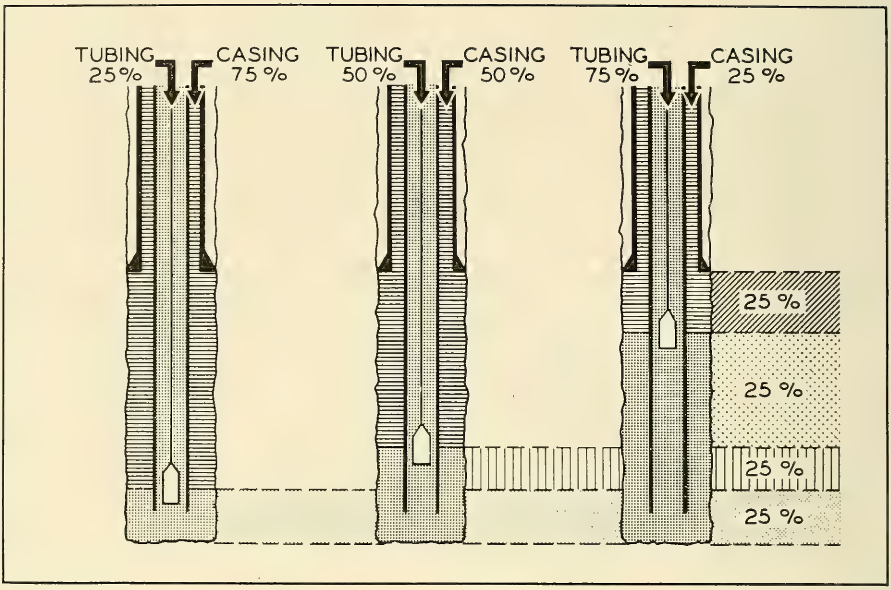


FIGURE 20-7. In a static-interface survey, two fluids are injected down tubing and casing simultaneously; proportional rates of flow control depth of interface, as determined by amounts of fluid accepted by various subsurface zones.

through the annulus, an interface will develop between the fluids at some depth in the well below which only the first fluid enters the formation. The interface is detected by a conductivity cell located on the outside of the tubing and connected by appropriate leads to conventional instruments at the surface. The tubing string may be moved up and down through a stuffing box in order to locate or follow the interface. The injection rates of the two fluids are adjusted to a constant flow rate, so that their sum is the normal injection rate of the well. Separate determinations are made in which the proportional volumes of fluid injected down the tubing and annulus are altered. Detecting the point at which the interface stabilizes, locates the depth below which the fluid injected into the tubing (10%, 20%, etc., of total injected fluid) enters the formation.

The fluid-velocity survey method is a comparatively recent development that has had extended field application. Its principle of operation is quite simple. While fluid is injected into the well at a constant, controlled rate, a subsurface flowmeter is lowered slowly to the bottom of the well. Fluid velocity data, as measured by this tool, is transmitted to the surface through an insulated electric cable and recorded on automatic instruments. As in the moving interface type of survey, each change in fluid velocity (corrected for variations in hole diameter) represents fluid loss into the zone being traversed. These changes

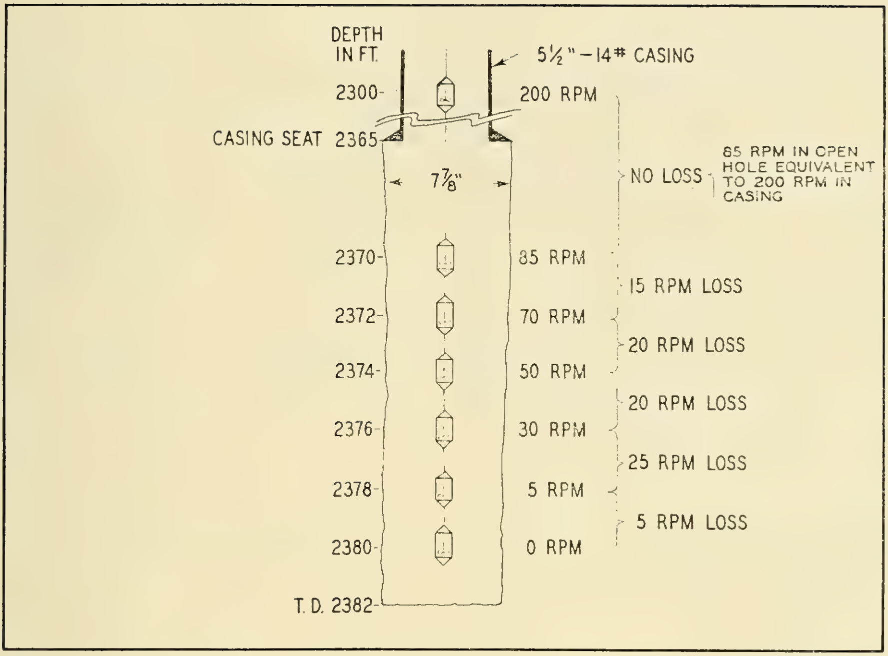


FIGURE 20-8. The "spinner" tool measures fluid velocity at various depths; relative injectivity of each subsurface zone is proportional to fluid lost into that zone.

are correlated with the depths at which they occurred, and the comparative permeability of the formation throughout the well bore is thus obtained. A number of different tools have been developed for use as subsurface flowmeters. The most commonly used instrument (fig. 20-8), usually referred to as the "spinner", consists of a metal guard cage in which a small, plastic impeller blade is mounted. When the instrument is suspended in the well bore, fluids passing through the cage in either direction cause the impeller blade to rotate. The speed with which the blade turns changes with the velocity of the fluid passing through the cage and is measured electrically. These data can be calibrated readily to yield fluid velocity in terms of feet per minute, which in turn can be converted into gallons per minute. By traversing the well with the spinner instrument and recording fluid velocity versus depth, one can readily determine the comparative permeability profile.

Another instrument (fig. 20-9) that has been utilized experimentally as a subsurface flowmeter is the so-called "hot-wire" tool, which operates on the principle of heat transference. A heated wire immersed in fluid will dissipate heat continuously into the surrounding fluid. The amount of heat lost per given time interval will depend on such factors as the temperature of the fluid

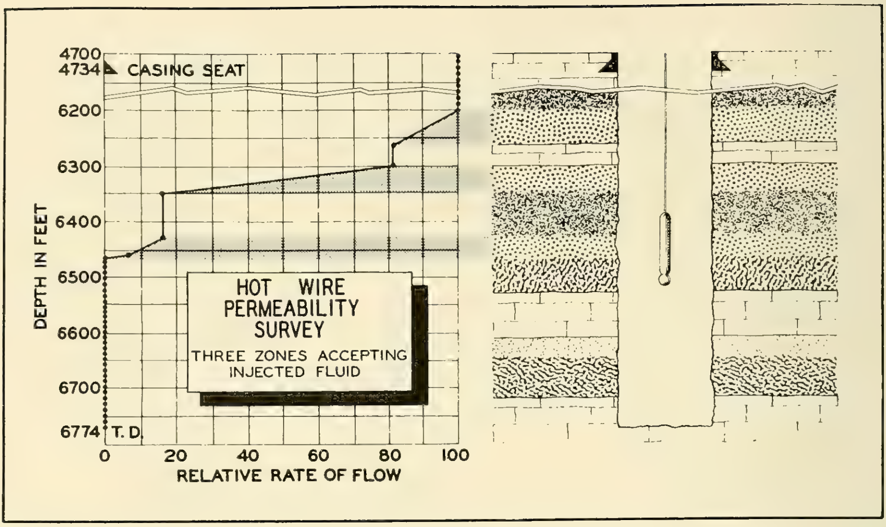


FIGURE 20-9. The "hot-wire" tool detects rate of fluid movement by measuring change in resistance of a heated wire, as a result of cooling effect of external fluid; degree of cooling is proportional to rate of flow.

medium and its heat conductivity. Any movement of the fluid surrounding the heated wire results in an immediate increase in the rate of heat loss. This increase is a function of the rate of flow of the fluid past the heated wire. Thus, by measuring the rate of heat dissipation from the wire, one can obtain an accurate and extremely sensitive measure of the velocity of the surrounding fluid.

INTERPRETATION OF DATA

Comparative permeability profiles are made to determine the thickness of the various permeable sections in the bore hole, the vertical position of these zones in the bore hole, and the relative capacities of the various zones. Also, data obtained from the permeability surveys may be used to calculate three different indices that pertain to the volume of fluid injected into the various permeable zones. The nomenclature for these various indices has been set up to correspond with the various productivity indices except that they are a measure of injected fluid rather than produced fluid.

In normal production practices, the term "productivity index" usually refers to the barrels of fluid produced each day, for each pound per square inch of differential pressure. In permeability surveying, the injected fluid is measured to get a term equivalent to the productivity index, except that the term represents injected fluid rather than produced fluid.

The standard terms or nomenclature used in permeability surveys are as follows: (1) capacity - the volume of fluid injected into an individual permeable zone in gallons per minute; (2) capacity index - the volume of fluid injected into an individual permeable zone in gallons per minute for each pound per square inch of differential pressure; and (3) specific capacity index - the volume of fluid injected into an individual permeable zone in gallons per minute for each pound per square inch of differential per foot of thickness of the zone at the bore hole.

The term "capacity" is the most generally used index for planning initial acidizing procedures. For most work-over jobs it is sufficient. For comparing permeability surveys on the same well before and after acid treatment, or before and after a work-over job, the capacity index should be used, since the injection rates into the various zones must be corrected for the differential pressure applied.

The "specific-capacity index", which is a direct measure of the actual effective permeability of each permeable zone, appears to be valuable in locating undesirable water or gas zones in a well, particularly in intermediate zones producing these fluids. Where a well is producing from a series of breaks or permeable zones, all of which are connected to a common water or gas reservoir, it is reasonable to assume that the most permeable zones will be depleted of oil more rapidly and that water or gas encroachment will begin through these particular zones.

It should be noted that the comparative-permeability survey is used to determine only the position of the permeable zones in the well, the thickness of these zones in the bore hole, and the relative capacities of the various zones. It is not used for direct determination of saturation, porosity, or fluid content of the permeable zones, although when used in connection with other well information or well logs it will assist at times, in the evaluation of the fluid content of such zones. These particular comparative-permeability logs, in their role of locating and evaluating zones with respect to permeability, appear to be more reliable and accurate than any other method in use.

The comparative-permeability survey cannot replace or detract from the value of other well-logging methods that show the saturation or fluid content of the producing horizon. In work-over jobs, acidizing work in particular, saturation and fluid-content logs should be used in conjunction with the permeability survey in planning the program. The permeability survey as it is applied now has an accuracy of only about 95 or 97 percent; therefore the permeable zones in a producing horizon that contain 3 to 5 percent of the total capacity of the well may not be recognized. This does not mean, however, that these zones will not produce oil if they are acidized properly. A number of instances have occurred where zones, indicated as impermeable because of mudding or other factors, have shown good saturation on the sample log. After selective acidizing of these zones, production was greatly increased. Also, in instances where no permeability is indicated, and the well then is acidized selectively, a survey following the acid job often shows that the permeability of the zone has been increased.

Surveys for locating and evaluating permeable zones play a major role in solving the problems of reservoir control, in the control of individual wells, in well completion, and in acidizing and work-over operations.

When an attempt is made to produce a field as a unit, it is necessary to know as much as possible about the mechanics of drainage and movement of fluids in the reservoir. For example, consider a limestone reservoir in which the production is from a series of permeable and porous lenses with little or no vertical communication. The most efficient method of producing such a reservoir is to deplete all lenses or zones at such a rate that water or gas does not encroach prematurely on any individual member.

Knowledge of the positions, thicknesses, and capacities of permeable zones in each well, as it is completed during the development of the field, is valuable. When correlated with other information such as structural position, gas-oil and water-oil contacts, and fluid-content logs, the permeability survey data assist materially in programming optimum perforating, acidizing, shooting, and work-over operations.

Owing to the variability of the porosity and permeability of limestone reservoirs, any simultaneous acid treatment of two or more zones frequently results in the productivity of one zone being greatly increased and that of the other only slightly increased. Permeability surveys made before and after acid treatments have shown this to be true in most cases. Such surveys also have shown that the zone having the greatest capacity before treatment may not have the greatest capacity after treatment. It is not always possible to predict which of the several zones will be benefited most by a simultaneous acid treatment of all zones.

SELECTION OF METHOD Selection of the best method of obtaining comparative permeability data takes into consideration a number of factors such as cost, reliability, time required for conducting the survey, and individual well conditions.

In general, the spinner flowmeter type of survey is run most easily and quickly. This survey is accurate and requires the injection of only one fluid into the formation. It can be run in any type of well fluid, including water, oil, drilling mud, and in some instances, gas. One limitation of this tool is that the delicately balanced impeller blade may become entangled with solid materials such as shale, gravel, paraffin, rope fibers, or other lost circulation agents, thus giving erroneous readings. Its principal limitation, however, is that the accuracy of the measurement decreases sharply at fluid velocities of 3 feet per minute or less.

The moving-interface survey is extremely accurate, even at very low fluid velocities. Many operators, however, object to having both oil and water injected into the formation. The conductivity electrode tool requires the use of two dissimilar fluids. Although brine and fresh water can be used for this purpose, the interface is less distinct than when oil and water are used. An advantage of the photoelectric tool is that only a single fluid is injected into the formation. The soluble dye has no deleterious effect on the formations. On the other hand, oil, or other foreign substances that sometimes coat the operating lenses of the tool cause trouble.

The static-interface method has the advantage of not requiring an auxiliary caliper survey for interpretation. This is not true of the methods discussed above. The cost and inconvenience of running tubing more than offsets this advantage. The method is particularly adapted, however, to running surveys in shot holes in which other methods fail.

NEW DEVELOPMENTS IN RADIOACTIVE TRACER TECHNIQUES

Since the advent of atomic power, with the accompanying availability of relatively inexpensive radioactive isotopes, new permeability-surveying techniques have been or are being developed. Radioisotopes have been adapted for use with all four of the above-described surveying methods.

In one form of permeability logging using tracers, a log of the natural radioactivity of the formation is obtained first. Fluid, containing a colloidal dispersion of fine, insoluble radioactive particles, is then injected into the well. A second radioactivity log of the well is then made and compared with the first. Radioactive particles are deposited on the face of the well bore at the point the fluid enters the formation. The amount of radioactive material deposited is proportional to the amount of fluid entering. Accordingly, the increase in radioactivity as determined from the two logs is used to locate and evaluate all injection zones in the well.

Another application of radioactive tracers is made as follows: A small amount of concentrated solution of radioactive material is spotted by a bailer in the fluid column. Injection is started at the surface, and the radioactive marker is followed down the well bore by a Geiger counter. The resulting survey is interpreted in the regular manner. This type of survey has the advantage of using either oil or water in the hole. Also, the Geiger-counter readings are unaffected by any contaminants in the well bore.

In using radioactive tracers for the static-interface survey, normal procedures are used. The same fluid is used in both tubing and annulus, except that one contains a lower concentration of dissolved radioactive material. The location of the static interface at different pumping rates is detected by the Geiger-counter tool. The advantage of this method over the regular static-interface method is that the tubing need not be raised to locate the interface. In this instance, the Geiger counter is run inside the tubing and locates the interface in the annulus, as though there were no tubing in the hole.

In velocity surveys, a tracer method that has been developed uses a long surveying tool containing a reservoir of radioactive material in the upper end and a Geiger counter in the lower end. Fluid is injected into the well at a constant rate from the surface as in normal velocity surveys. The combination tool is suspended at a known depth in the well, and small increments of radioactive material are ejected into the passing fluid stream. The fluid velocity is determined from the time interval required for the radioactive tracer to travel from the top to the bottom of the tool. Similar determinations are made throughout the well bore, and data for comparative-permeability profiles are obtained.

Many other applications have been and are being developed whereby valuable subsurface data may be obtained through the use of radioactive isotopes. For example, casing and tubing leaks may be located without removing the string from the well. Channeling behind cement can be detected. In several instances the detection tool has been placed in the tubing just above a formation packer for the purpose of detecting a packer leak immediately whenever one should occur. Another successful application has been in determination of zones of lost circulation in drilling wells. Radioactive tracers also can be used to control the application of acid in selective acidizing treatments.

Although there is still much to be done in perfecting application techniques and properly interpreting the data, the use of radioactive isotopes appears to have an unlimited application in the oil industry. Tracers are a valuable new tool which will assist the engineer and operator in making proper application of completion or remedial treatments.

The growing interest in research on physical conditions and performance of petroleum reservoirs has led to the development of many new and improved instruments and techniques for permeability surveys. Continuing research promises future discoveries and developments that will permit greater ease and speed of surveying, and even greater accuracy of data.

Chapter 21

CONTINUOUS VELOCITY LOGGING (Acoustical Logging)

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S. W. Schoellhorn
and
R. B. Baum

As a general service to the oil industry, continuous velocity logging, or acoustic logging, is approximately three years old. Even with this short period of experience, many observations indicate that the continuous velocity log will make valuable contributions to the information obtainable from a drilled hole.

The first commercial continuous velocity log was run in the Stanolind's Daisy Perdasofpy No. 1, Comanche County, Oklahoma, on March 6, 1954. This survey was performed by Seismograph Service Corporation of Tulsa, using under license agreement, the Magnolia Petroleum Company Continuous Velocity Logger. In recent years Magnolia, Shell Oil Company, Humble Oil and Refining Company, United Geophysical Company, and The Texas Company have pioneered in the development of velocity logging tools. Magnolia began its work about 1950. Very little published information, except for that on the Magnolia tool, is available on the details of the various instruments constructed.

The Magnolia Continuous Velocity Logger now in commercial use, and more commonly described as the CVL logger, consists of a transmitter and a single receiver. The direct presentation, without photographic recording delay, of both the interval log and the integrated travel-time curve, are unique to this system.

SPECIFICATIONS AND EQUIPMENT

A simplified drawing of the essential components of the Magnolia logger is shown in Figure 21-1. The system contains a magnetostrictive nickel alloy transmitter. The expansion of the alloy, when magnetized by the electric current supplied from the logging truck, produces the sonic pulses which are emitted approximately 20 times each second, with a frequency spectrum of about 10-20 kilocycles per second. The transmitter is separated by a 6-foot acoustic insulator from a single receiver which consists of a stack of tourmaline crystals. Each pulse is automatically timed over the distance represented in the illustration by time interval t_i and is recorded to form a continuous log. Logging may be conducted at speeds up to 100 feet per minute.

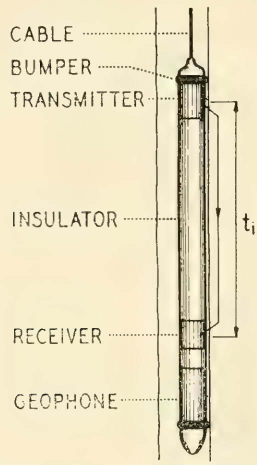

FIGURE 21-1. Continuous velocity logger.

The instrument is capable of continuous operation at temperatures up to 350F and at pressures up to 15,000 psi. Over-all length of the tool is 11 feet, the outside diameter is 3⅜ inches, and its vertical movement is controlled by a standard cable and hoist truck of the type operated by Schlumberger. The nose of the instrument is equipped with an adapter to which a well geophone may be attached. Thus, both tools can be run in the hole simultaneously. The log is ordinarily recorded on the "out run" without interruption, but may be taken between shot levels of a geophone survey.

The standard well geophone now provided for use with the Seismograph Service Corporation logging operations is a development of Gulf Research and Development Corporation. This well phone is a high-gain, pressure-sensitive detector having relatively low sensitivity to movement of the cable and to other vertical movements. Figures 21-2 and 21-3 are photographs of the instruments and a typical velocity logging truck.

The logging truck is shown in Figure 21-2 and a close view of the CVL surface instruments as mounted in the truck for convenient operation is shown in Figure 21-3. In the center of Figure 21-3 is the CVL 2-pen recorder which plots interval velocities and integrated travel times versus depth. At the top right is the auxiliary panel containing the depth counter and the intercommunication system with the cable truck. In the middle right is the CVL measuring panel with the precision electronic measuring equipment which includes a monitor oscilliscope. The meter on the left indicates interval times in microseconds. At the bottom right is the power supply panel. Power is furnished by a 1.5-kilowatt gasoline-driven generator. On the left, at the rear of the truck, is the 12-trace seismic equipment which is used to record well geophone travel times whenever calibration of the integrated travel-time curve is required.

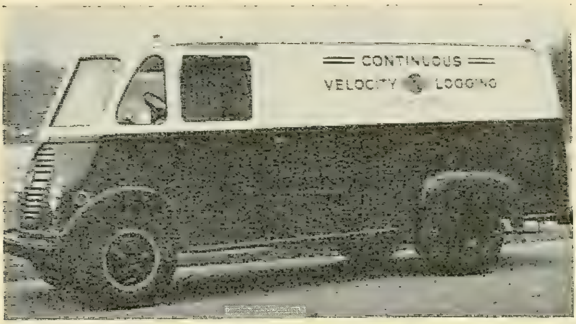

FIGURE 21-2. CVL truck.

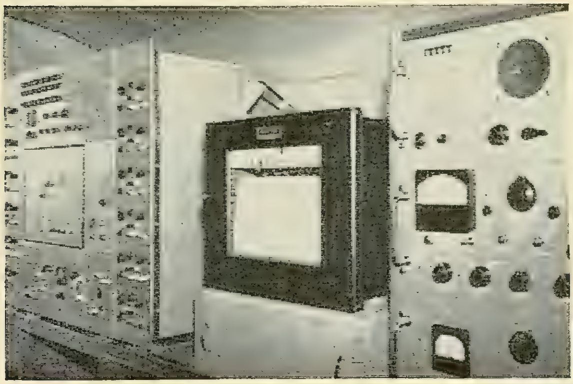

FIGURE 21-3. CVL truck — interior view.

THEORY

A pictorial diagram of the continuous velocity logger is shown in Figure 21-4. The basic principle of the system is that during recording a voltage is produced which is proportional to the time elapsed between transmitting and receiving the signal. This voltage is impressed on a galvanometer GAL-1 whose pointer traces the value of the interval time t_i directly on the log at the indicated depth. The over-all travel time T for the interval logged is traced simultaneously on the log by the pointer of galvanometer GAL-2, which is activated by a ball and disc type integrator. This device continuously integrates the interval time t_i with respect to the distance Z travelled by the logger. The instrumentation is described in detail by Summers and Broding (1952).

Basically, a log of the formations penetrated is developed by obtaining velocities over short intervals. This is accomplished by the measurement of the travel time (t_i) of the sound wave through the formation sidewalls over the distance separating the transmitter and receiver.

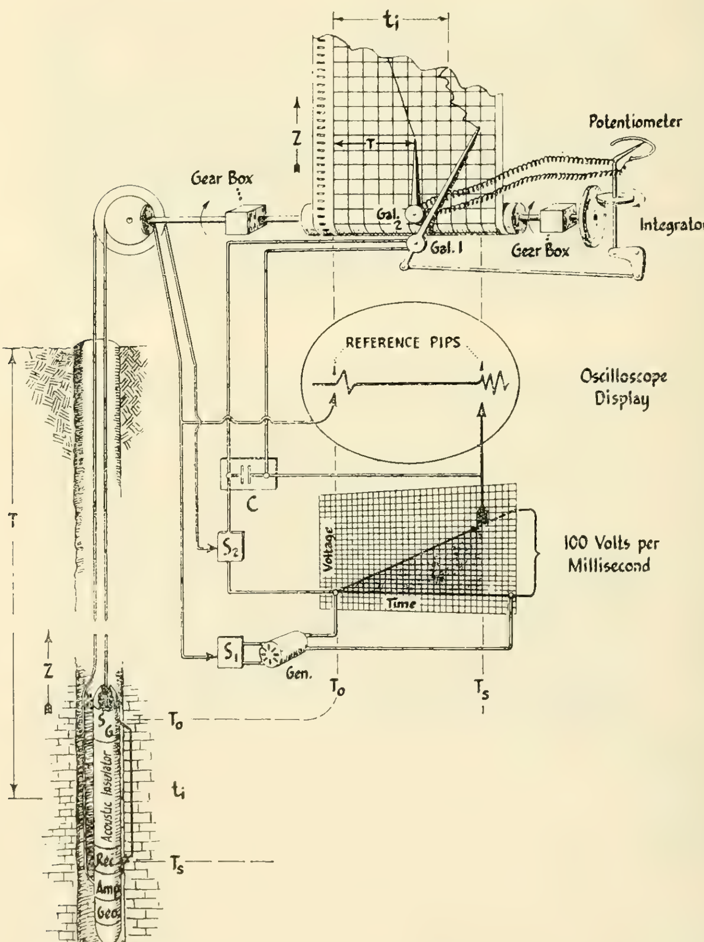

FIGURE 21-4. Pictorial diagram of continuous velocity logger.

Velocity is a function of the elastic constants of the formation and as such represents a new logging parameter. Velocities increase as the degree of compaction and the geologic age increase. Shales may be identified on the log by their relatively low velocities. Higher velocities are indicative of sandstones, limestones and dolomites. The resulting logs are very readily correlatable between wells.

In addition to its use for correlation and for qualitative analysis of sediments, the CVL log also offers measurements of the over-all average velocity through the logged section. The total travel time through the section is computed by the integrating device in the instrument. This travel time is portrayed by the integrated curve, and when used in conjunction with two or more recorded travel times to a well geophone, yields accurate average velocity information to the various horizons logged.

EXAMPLES AND APPLICATIONS OF VELOCITY LOGS

Velocity Log Relates Lithology and Velocity

Figure 21-5 shows a continuous velocity log of a well in Caldwell County, Texas, along with the geologic section, and demonstrates the relationship between lithology and velocity. The Lower Cretaceous section shown includes the Hensel, Cow Creek, and Sligo formations and penetrates the Hosston. The more prominent shale and limestone breaks are indicated on the geologic log on the left. The presence of the thin shale breaks at 3580 and 4325 feet are effectively demonstrated by the interval velocity curve on the right. The over-all average velocity is obtained from the integrated travel time curve shown on the log as a fairly straight line. This curve corresponds with the familiar time-depth curve obtained from travel times to a well geophone.

Velocity Logs Compared With Electrical Logs

Comparison of electrical and acoustic characteristics is shown in Figure 21-6. These are logs from two wells in Gonzales and Caldwell counties, Texas, separated by a distance of more than 50 miles. The self-potential, resistivity, and interval velocity curves are displayed for each well, and the identification of formations indicated. The character correlation of the Eagle Ford section is particularly noticeable, despite reduction in thickness in the Caldwell County well. Also of interest is the velocity relationship between the Georgetown and Edwards limestones as compared with their electrical curves. The increased resistivity shown at the top of the Georgetown and again at the top of the Edwards at the Caldwell County well (left) is not maintained at the Gonzales County well (right). The velocity log, however, reveals identical correlation at the Georgetown and shows consistently high velocities in both wells at the Edwards.

In general, there is correlation between the velocity log and the resistivity log. In some cases reverse correlations are noted. Both normal and reverse correlations are significant in determining lithologic character and fluid content of formations. Hicks and Berry discuss the normal and reverse correlation of

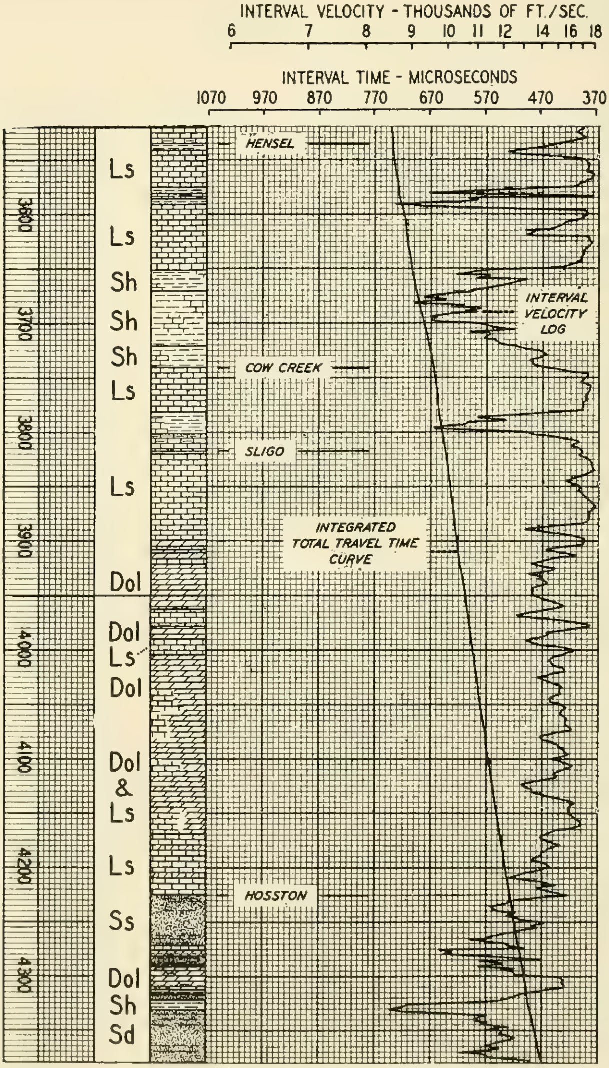

FIGURE 21-5. Velocity log and geologic log, Caldwell County, Texas.

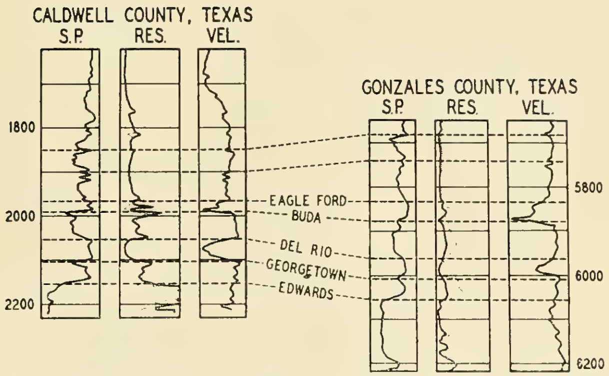

FIGURE 21-6. Comparison of velocity logs and electrical logs, Texas.

velocity logs with elecrical and radioactive curves and show excellent examples in their paper published in 1956.

Another velocity log-electrical log comparison shown in Figure 21-7 illustrates how the velocity log may supplement the electrical logs in correlation studies. The Woodford-Hunton-Sylvan-Viola sequence persists over central Oklahoma. A velocity log taken from the files may be identified as an Oklahoma log by examining the recorded velocities in this part of the log, almost as easily as by reading the location from the log heading. The geologist sitting on the well in which these logs were run had no diffculty picking the top of the Hunton from samples, but the electrical curves alone do not indicate this interface with certainty.

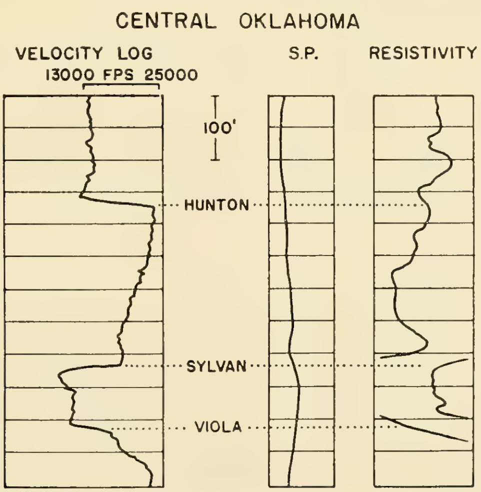

FIGURE 21-7. Comparison of velocity, SP., and resistivity curves, central Oklahoma.

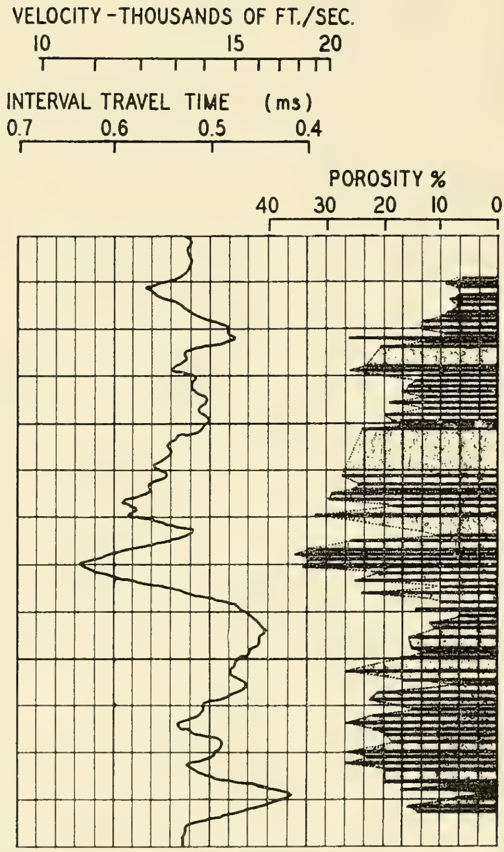

Figure 21-8. Correlation of velocity log and limestone porosity.

The Viola has been the objective seismic horizon in central Oklahoma for years. The number of seismic maps labeled "Viola" which have been prepared from Hunton data probably is considerable. The continuous velocity log can end much of the controversy over the correct identification of reflections obtained from this zone.

Velocity Log Compared With Limestone Porosity

The results of an experimental investigation by Magnolia Petroleum Company to correlate interval velocity with limestone porosity is demonstrated in Figure 21-8. The envelope of the porosity log shows marked similarity to the interval velocity curve, increased porosity with decrease in velocity. Cores were taken in this experiment and porosity values were obtained in the laboratory, as

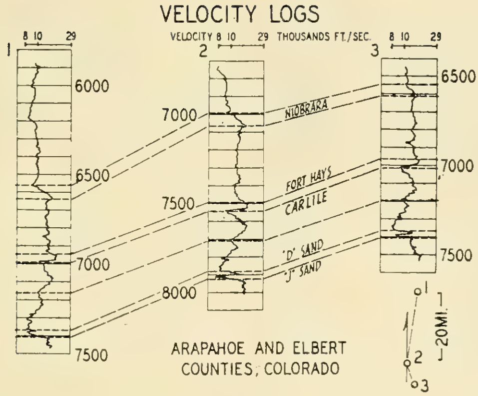

FIGURE 21-9. Velocity log correlations, Arapahoe and Elbert Counties, Colorado.

indicated by the horizontal bars. Absence of a sample is indicated by the absence of a bar. It is believed that this application of velocity logging can be refined to furnish quantitative porosity data, and, therefore, will be a major contribution to well completion practices. Recent studies on the relationship between porosity and velocity by Wyllie, Gregory and Gardner (1956), and Hicks and Berry (1956), indicate that the porosity of a formation exerts great influence on the apparent velocity through the formation.

Velocity Logs Showing Geologic Correlations

The next group of five illustrations is presented to demonstrate the good correlative characteristics of the velocity log. Figure 21-9 shows velocity logs of three wells in the Denver Basin, Arapahoe, and Elbert counties, Colorado.

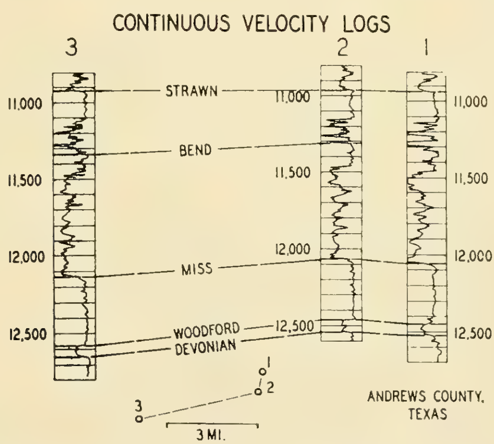

FIGURE 21-10. Velocity log correlations, Andrews County, Texas.

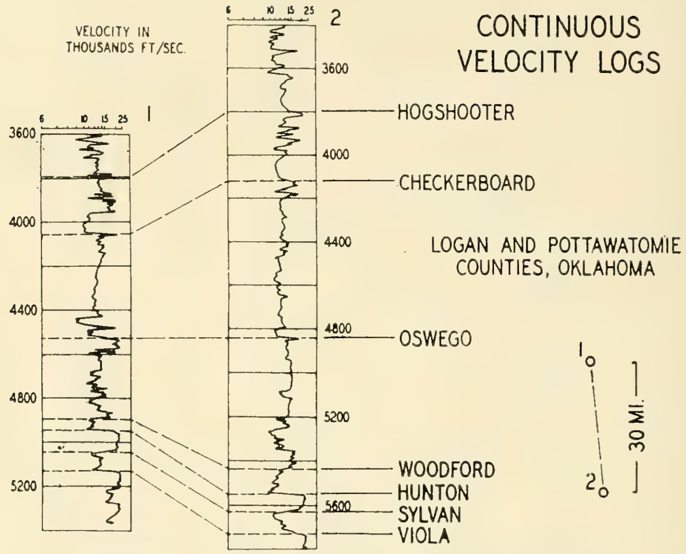

FIGURE 21-11. Velocity log correlations, central Oklahoma.

These logs are referred to a sea-level datum and show the relative structural position of the wells. The correlations of the Niobrara, Fort Hays, Carlile, and "D" and "J" sands are clearly demonstrated. The distance between Wells 1 and 3 is 25 miles.

Figure 21-10 shows velocity logs of three field wells in Andrews County, West Texas, and indicates the good correlative characteristics of the horizons from the Pennsylvanian Strawn to the Devonian. Figures 21-11 and 21-12 show

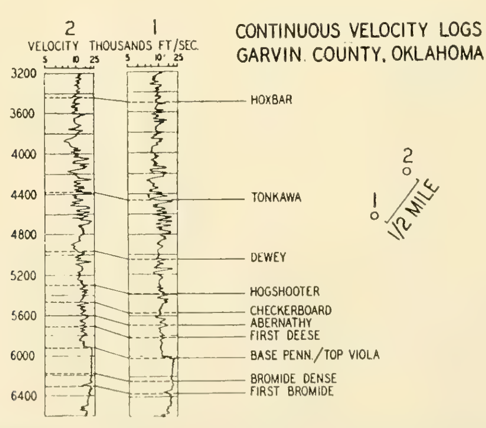

FIGURE 21-12. Velocity log correlations, southern Oklahoma.

velocity logs of two wells in central Oklahoma and two wells in southern Oklahoma revealing good correlative quality. The wells in Figure 21-11 are about 30 miles apart and the wells in Figure 21-12 are ½ mile apart. The deep pre-Pennsylvanian correlations are distinct in both illustrations. The character of the Pennsylvanian section shown in Figure 21-12 is considered typical for Pennsylvanian logs.

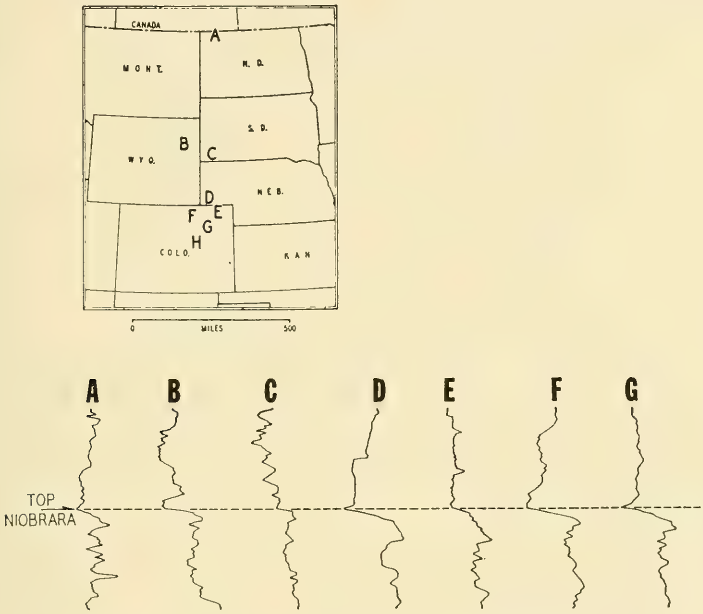

FIGURE 21-13. Velocity log correlations over long distances.

As demonstrated in Figure 21-5, the log is considered unique in that it portrays the relationships between velocity and lithology, and the influence of compaction and geologic age. The log provides a direct measurement of a physical property of the formation. Therefore, it is possible in many instances to identify the log geographically by simply associating the observed velocities to lithology and reasonable geologic age. For example, a Gulf Coast log is easily identified by the thick sections of relatively low-velocity material and Oklahoma logs are easily identified by the distinct Pennsylvanian and pre-Pennsylvanian velocity contrasts.

The excellent quality of velocity log correlations over long distances is revealed in Figure 21-13. The top of the Niabrara is shown to virtually write its name on eight logs of wells located over distances in excess of 600 miles across North Dakota, South Dakota, Wyoming, Nebraska, and Colorado.

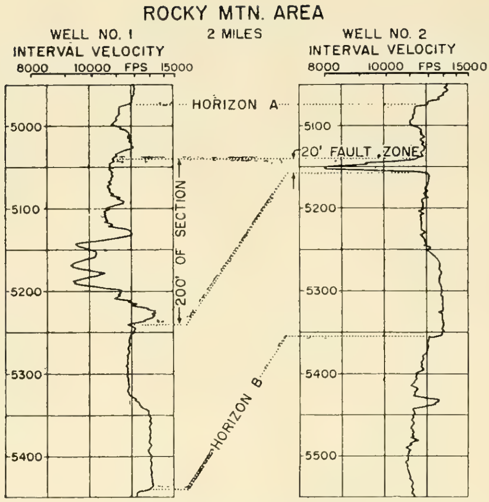

FIGURE 21-14. Velocity logs, Rocky Mountain area.

Velocity Logs Solve Geologic and Seismic Problems

Further applications to geological and geophysical problems which may be solved through the use of velocity logs are shown in Figures 21-14 and 21-15. Velocity logs are shown in Figure 21-14 of two wells in the Rocky Mountain area and are located approximately 2 miles apart.

Well No. 1 has 200 feet of section present which is cut out by faulting in Well No. 2. The over-all section indicates interval velocities of approximately 12,000 feet per second, except that in a zone comprising 20 feet of section in Well

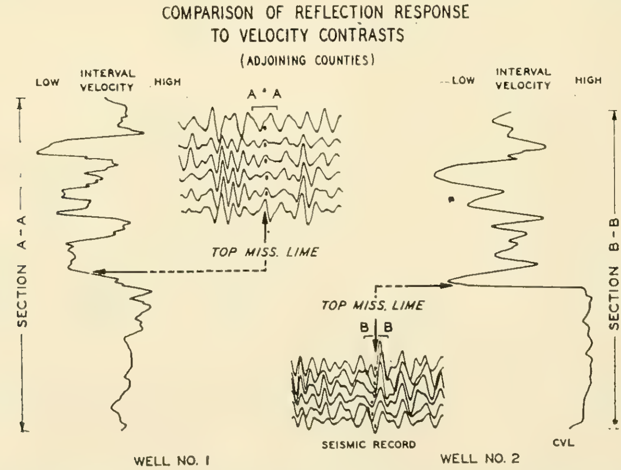

FIGURE 21-15. Comparison of reflection response to velocity contrasts.

No. 2, where the 200-foot section of Well No. 1 is missing, extraordinarily low interval velocities are observed. This velocity of 8000 feet per second is not representative of the geologic section and apparently is the velocity of the brecciated fault zone. Additional evidence has been observed recently to indicate that faults can be identified by anomalous low velocity response of this type.

The continuous velocity log provides the geophysicist with a method for determining the origin of seismic reflections. Figures 21-15, 21-16, and 21-17 are

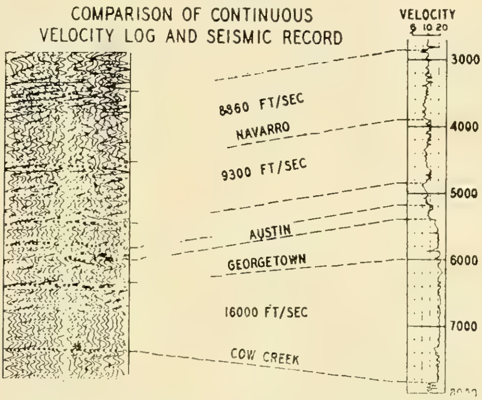

Figure 21-16. Comparison of velocity log and seismic record.

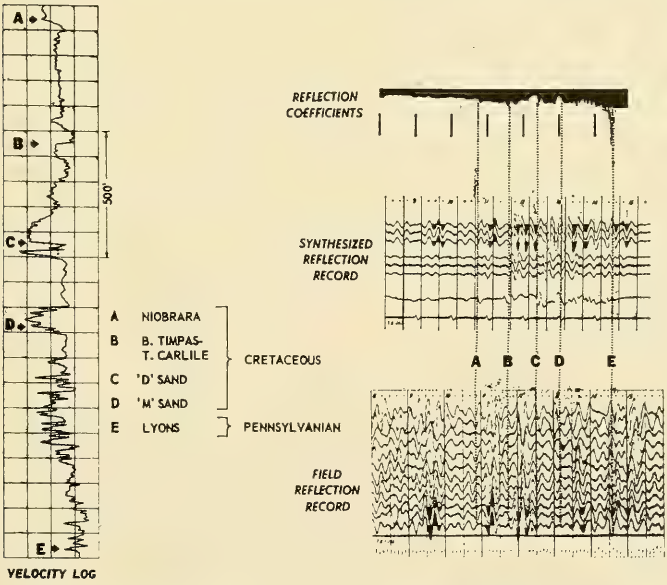

Figure 21-17. Velocity log and synthesized reflection record.

used to demonstrate the close relationship between seismic reflections and deflections of the interval velocity curve on the CVL log. Figure 21-15 shows an interesting comparison of reflection response to velocity contrasts. The illustration reveals that good seismic reflections are obtained from a given horizon in certain instances but are not obtained in other instances in the same local area. The velocity log of Well No. 2 (right) shows a sharp velocity contrast at the top of the "Mississippi lime." The corresponding position on the seismic record obtained at the well reveals the presence of a good quality reflection. The velocity log of Well No. 1 (left) shows only a gradational velocity contrast at the "Mississippi lime." The corresponding position on the seismic record fails to reveal the presence of a recognizable reflection. Therefore, the conclusion is warranted that changes in quality and character of a particular reflection may be correlative with changes in stratigraphic conditions. Increased shale content of sands or limestones, or the local appearance of increased porosity, should affect reflection response.

The close relationship between seismic reflections and abrupt deflections of the velocity curve is shown in Figure 21-16 and 21-17. It is observed in Figure 21-16 that reflections are associated with both increase in velocity, as at the Navarro and Austin, and decrease in velocity, as at "C" horizon and at the Cow Creek. The section between the Georgetown and Cow Creek shows high interval velocities, and the corresponding shortening of time interval on the seismic record is well illustrated by the convergence of the correlations below the Austin.

A seismic reflection record synthesized in the laboratory from the velocity log, along with the actual field seismic record obtained at the well, is shown in Figure 21-17. The reflection character correlation between the two seismic records is good. A synthetic reflection record can be prepared from any velocity log. Its application to seismic exploration work can be invaluable since it can solve many difficult reflection identification problems. In addition, the synthetic record may furnish the yardstick by which the reflection record quality of a contemplated seismic exploration program can be measured. The velocity log then may be used as a partial substitute for an experimental program from which the standards of reflection response in an area are obtained and by which instrumental techniques or adjustments effected to insure reflection records of optimum quality.

Velocity Logs Faithfully Reproduce Formation Characteristics

The features shown in Figures 21-9 through 21-15 demonstrate that the velocity response affords reliable correlative character at different wells separated both by long and by short distances. Figures 21-18 and 21-19 furnish added proof that the CVL log portrays detailed formation characteristics accurately. Logs run at different times in the same well are shown in Figure 21-18. The duplication achieved between the separate runs is excellent. Not only were the logs run three weeks apart, but the first log was recorded with automatic tracking techniques while manual tracking was used to record the second log.

The second illustration, demonstrating the faithful reproduction of formation characteristics, displays the type log produced in isotropic media of salt and anhydrite. Constant velocity conditions are expected to exist and are so recorded on the log (fig. 21-19) by the extremely smooth curves shown. The lithology is apparent from the velocities recorded: anhydrite approximately 20,000 feet per second and salt approximately 15,000 feet per second. Also, fidelity of recording is not affected by the highly saline drilling fluid.

The low velocity deflection shown at the top of the salt plug results from a solution cavity and can be corrected by use of caliper data. In general, it is found that drilling in the softer formations results in larger hole diameter. This condition, therefore, occasionally produces an expected correlation between the

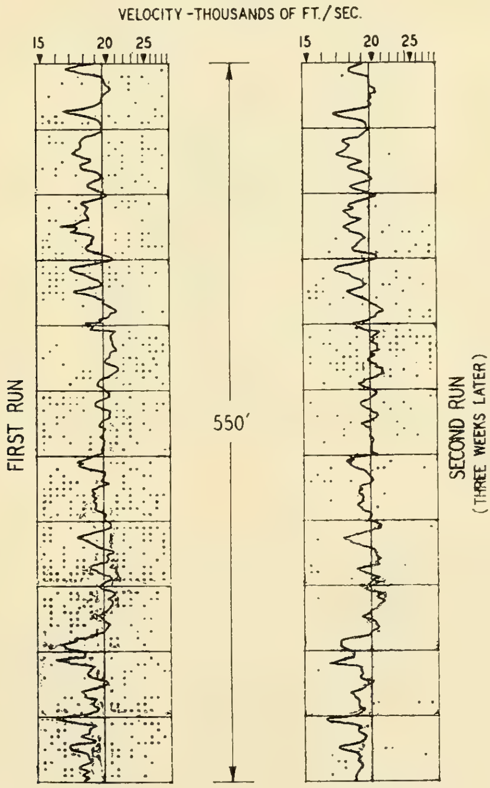

FIGURE 21-18. Velocity logs illustrating duplication in same well.

caliper log and the velocity log. The caliper log run in this hole showed the abrupt increase in hole size so that an exaggerated velocity deflection is recorded. Fortunately, pay zones are usually competent and do not wash, so that the caliper effect can be neglected. In the average borehole the sum of the recorded errors in over-all velocity which affects the integrated travel-time curve, and which are attributed to fluid travel time in cavities, seldom exceeds 4-5 milliseconds. The magnitude of this error is comparable with that inherent in the standard seismic geophone survey.

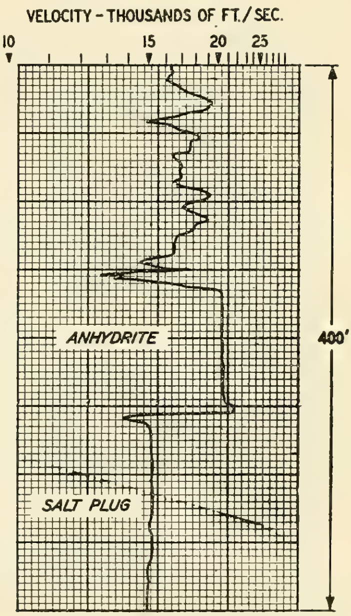

FIGURE 21-19. Velocity log in isotropic media.

Velocity Logs, Geographic Distribution

Figure 21-20 shows the approximate locations of SSC continuous velocity log surveys performed in the United States and Canada during the first few years of service to the industry. The coverage is growing rapidly and it is expected that much more will soon be learned about the velocity log. At the end of November, 1956, approximately 900 logs had been run by Seismograph Service Corporation throughout the United States, Canada, Mexico, Venezuela, Europe, and North Africa. Logs run by Magnolia, Empire Velocity Service Company, and others bring this total considerably higher.

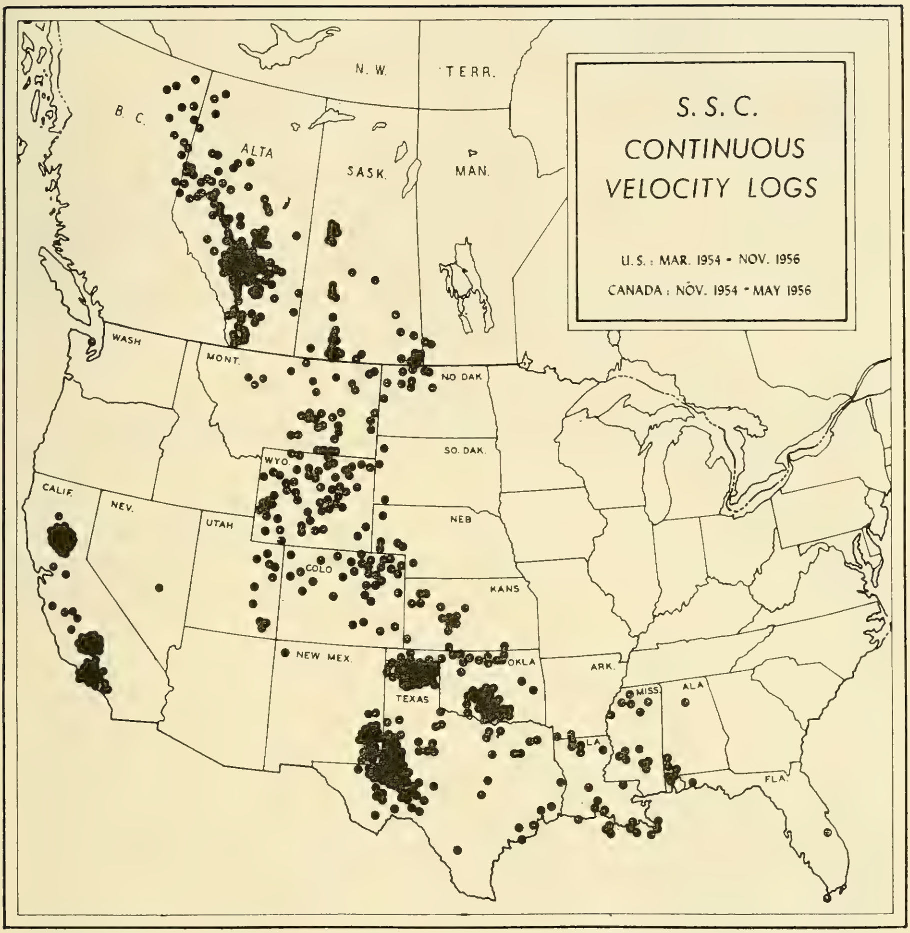

FIGURE 21-20. Distribution of SSC velocity logs in United States and Canada.

SUMMARY AND CONCLUSIONS

For the geophysicist, the continuous velocity log is rapidly replacing the detailed conventional geophone survey, because the data obtained enable the geophysicist to identfy seismic reflecting horizons and determine their actual depths. Also, the interval velocities obtained by the continuous velocity logging method are more accurate than those obtained from conventional geophone surveys. Furthermore, as the industry is gaining more familiarity and confidence in continuous velocity logs, a material reduction in cost of velocity surveys is being realized because the continuous logging survey requires less time at the well site than is required by the detailed standard geophone survey.

As a result of synthesizing records from continuous velocity logs, the geophysicist will be able to develop better instrumentation for further improving the accuracy and quality of data obtained from seismic surveys.

From the standpoint of the geologist the velocity log provides another correlation parameter, since the log is derived from a physical property heretofore not measured in boreholes. Of the various correlation parameters available, it is believed that velocity is the strongest single parameter. The continuous velocity log survey can provide: (1) a log revealing outstanding correlation data; (2) a log which can show small changes in lithologic character; (3) a log for differentiation of stratigraphy in thick limestone, dolomite, sand, and shale sections; (4) a log which can reveal fault contacts under proper conditions; and (5) an effective log in highly saline drilling fluid.

Further, initial studies indicate that velocity variations within a formation are related to porosity changes and that qualitative and quantitative analyses are possible.

It is the writers' opinion that the continuous velocity log will be invaluable in supplementing data provided by electrical and radioactive logs, and as the velocity log gains acceptance among geologists and petroleum engineers, the geophysicists will receive the by-product of velocity information at considerably reduced expense.

Reprinted from The Bulletin of the American Association of Petroleum Geologists v. 41, no. 8, August, 1957, p. 1667-1682.

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Chapter 22

MAGNETIC WELL LOGGING

R. A. Broding

Magnetic well-logging methods were first devised as an aid to the exploration geophysicist for control in interpretation of surface and airborne magnetometer surveys. Because of the limited magnetic surveying now being done, this logging method has not been widely used. However, during this development other uses for the log have been suggested. The following review of the present state of magnetic well logging is presented to show some of the applications in which magnetic logs have been used, with the anticipation that their application to the solution of unique logging problems will stimulate their use. Much of the data used in preparing this chapter were furnished the author through the courtesy of the Magnolia Petroleum Company.

The magnetic properties of rock can best be measured and evaluated from magnetic susceptibility and total field measurements. Magnetic susceptibility is a measure of the ability of rock to be magnetized and is considered to be the most significant magnetic property. It is measured by applying an external magnetizing field, H, to the rock and then detecting the field resulting from the induced pole strength or intensity of magnetization, I. The expression $k = \frac{I}{H}$ relates k, the magnetic susceptibility to I and H. Because the detector measures the magnetic field, it is desirable in instrumentation to make use of an alternating

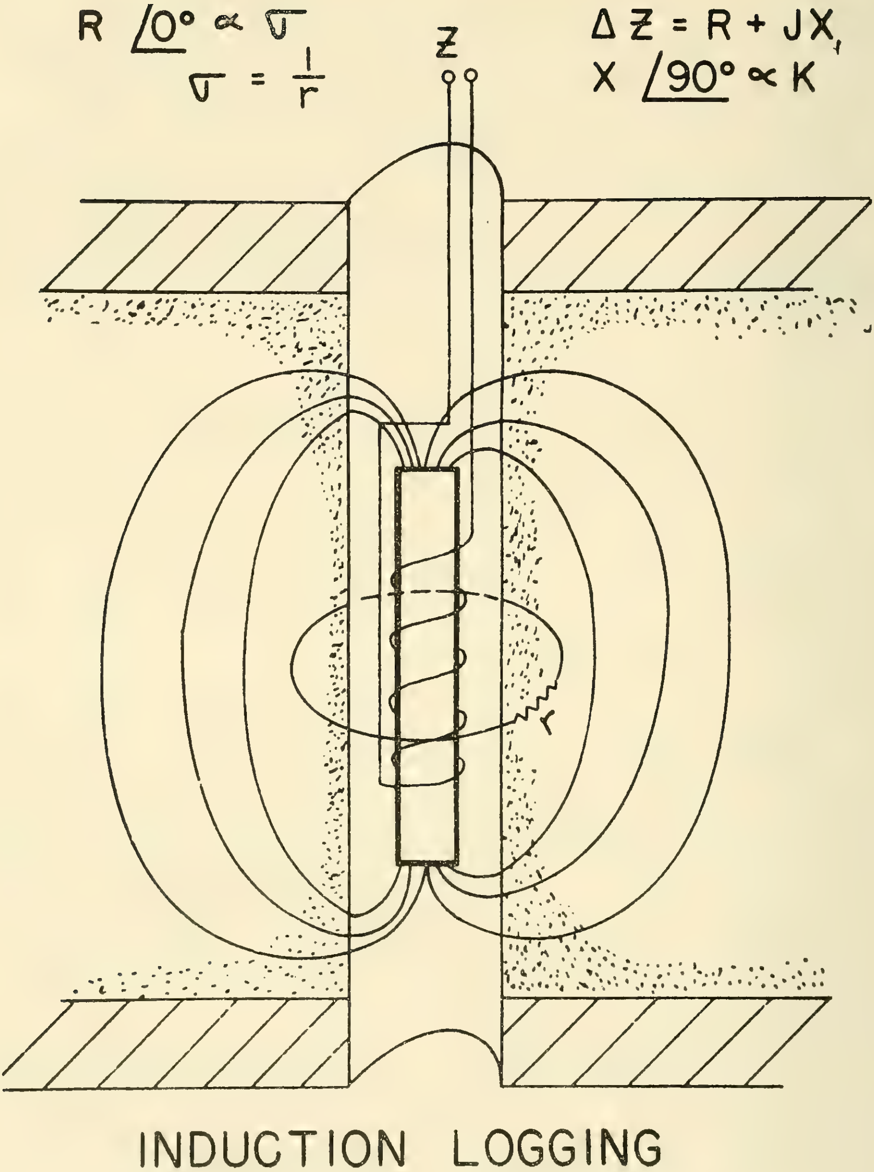

FIGURE 22-1. Mono Coil induction logging.

magnetizing force in the frequency range above 10 cps so that reasonable alternating-current (AC) amplifier or detection means can be employed and below 10 KC so skin effects are minimized. Such an AC measurement is free from remanent magnetization effects and allows a measurement of magnetic susceptibility alone. Because an external magnetizing force is required, the magnetic susceptibility instrument is classified as an induction logging tool.

Total field measurements reflect the sum of magnetic effects that are responsible for the magnetic field from the rock, that is, the remanent magnetism plus the field resulting from the magnetizing force of the earth's field in conjunction with the magnetic susceptibility of the rock. Surface magnetic prospecting schemes are complicated by the polarization of the remanent magnetism. Often it is not in the direction of the present earth's magnetizing force. For this reason the interpretation of total field borehole measurements is complicated, and such measurements have not been widely used.

INDUCTION LOGGING If an elongated solenoid with a low reluctance core is inserted in a borehole as shown in Figure 22-1, it will have a self impedance Z at a particular frequency. The resistive term reflects losses in the coil as well as eddy current losses in the rock surrounding the coil. The reactive term reflects the inductance of the coil, which is influenced by the susceptibility of rock in the external magnetic path. Thus, changes in rock conductivity will influence the resistive component, and magnetic susceptibility will influence the reactive component of the coil impendance Z.

If such a solenoid is placed in one arm of a bridge and excited at some frequency, as, for example, 1000 cycles per second (cps), the bridge will become unbalanced with changes in conductivity or susceptibility of the rock surrounding the solenoid. Because the unbalance voltages are in phase or in quadrature respectively, it is possible by phase detection to separate the two terms. Thus, they can be measured independently. A basic block diagram of such a system is shown in Figure 22-2. The coil and bridge are in the logging probe and are attached to the logging cable. The oscillator is at the surface and supplies excitation to the subsurface probe, as well as reference voltage to the phase sensitive detectors. The reference voltage to one phase detector is shifted 90 degrees with respect to the other. Thus, the signals are separated and are recorded on a dual-channel recorder.

The design of the sensing coil requires a compromise between a long coil for penetration into the formation and a short coil for delineating thin beds. A universal probe has been standardized, having a solenoid 21 inches long.

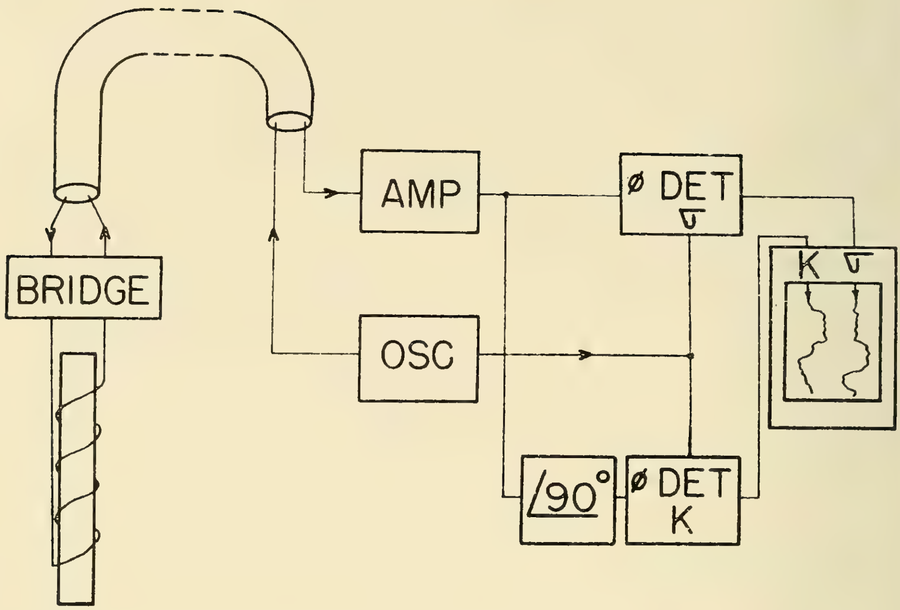

Figure 22-2. Block diagram of induction logging system. K = magnetic susceptibility. J = electrical conductivity.

For high-detail observations, a special contact-type probe is used in which the sensing coil is 3 inches long. The coil is kept in contact with the side of the hole by a bow-spring arrangement. This tool is referred to as a "Minimag" since it is a miniature magnetic tool.

Susceptibility probes of this type have a resolution of approximately 1 x 10^{-6} centimeter-gram-per-second (cgs) unit.

TOTAL FIELD LOGGING An adaptation of the flux-gate-type total-field airborne detectors has been made into a borehole probe. The sensing element is a saturable core magnetometer. It must be aligned in the direction of the total field by two aligning magnetometer elements at right angles to one another and in a plane perpendicular to the measuring element. The aligning elements operate a servo control to keep the measuring element in the direction of the total field. A simplified block diagram of the system is shown in Figure 22-3. The aligning coils are marked A and T, while the measuring coil is H. The borehole probe contains only the sensing elements, the servo drive motors, and the gimbal-supported table for the sensing elements. The electronics required to operate the tool is located at the surface. This tool has a resolution of approximately $\pm$ 1 gamma.

MAGNETIC SUSCEPTIBILITY LOGS

Magnetic susceptibility is a universal property, and rocks are classified as being diamagnetic if they reflect a negative susceptibility, and paramagnetic if they have a positive susceptibility. Relatively few rocks are diamagnetic (i.e., rock salt, anhydrite, coal, etc.), whereas most rock is paramagnetic. Generally, certain oxides of iron control the susceptibility because they are high compared to other oxides. The range of typical values for rock is from -0.4×10^{-6} to $+4000 \times 10^{-6}$ cgs units. Susceptibility is a natural property and is not necessarily specific to rock type. Certain rocks having high susceptibility have been correlated over miles, and the log has proven to be capable of identifying horizons that are peculiar to this logging method.

A comparison of a magnetic susceptibility log with other standard logs is shown in Figure 22-4. It has been found desirable in comparisons of logs to plot the magnetic susceptibility in the track normally used for the self-potential log and with increasing susceptibility to the left. This comparison illustrates the effect of bore-hole caliper on the log. In this particular case the drilling-mud susceptibility was higher than the average value of the sedimentary rocks. Thus,

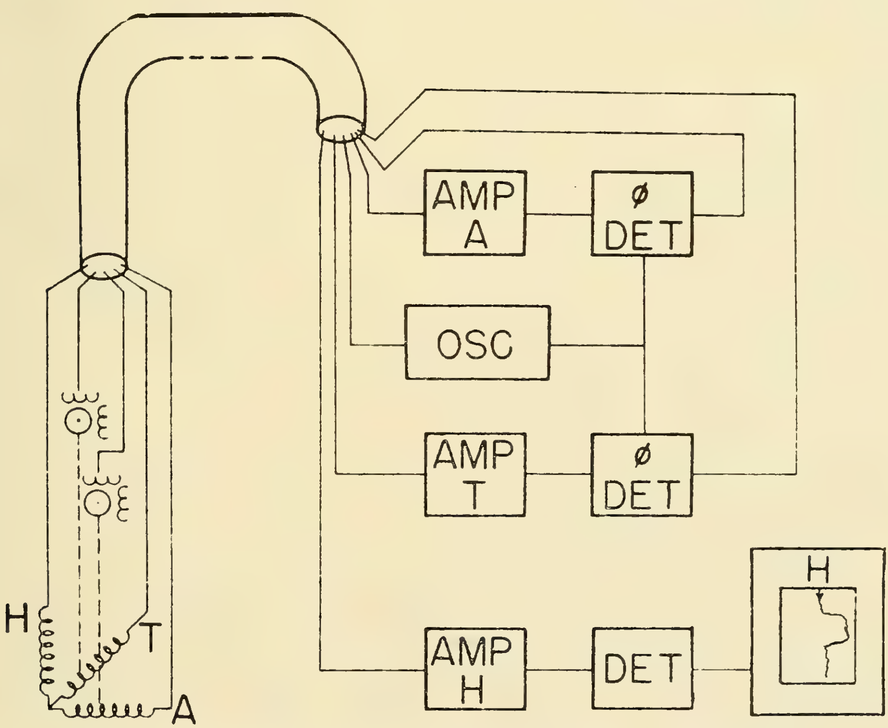

FIGURE 22-3. Block diagram of total-field logging system. H = total field.

there is an increase in susceptibility opposite zones of cavitation. If the drilling mud had a very low susceptibility, the susceptibility log would have decreased opposite zones of cavitation. To aid in this interpretation, a drilling-mud susceptibility measurement is made on a circulated-mud sample. Although differences between sands and shales can be measured, the most significant anomalies are generally associated with permeable zones or zones containing oxides of iron. Magnetite is the dominant oxide of iron that produces high magnetic susceptibility.

The good correspondence between the self-potential log and the susceptibility log suggests that enrichment of iron oxides in these zones has marked them. This concept has prompted the use of magnetic trace material in drilling muds to mark permeable zones or zones of lost circulation. The procedure involves adding a finely divided black iron oxide to the mud system. Such a tracer material is known commercially as "Magnafloat Grade B" and is marketed by the Foote Brothers Mineral Company. It is a black iron oxide which is primarily magnetite, with 90 percent of the particles less than 10 microns in diameter. The weight of the drilling mud must be kept high enough that the hydrostatic head of the fluid column in the bore hole is greater than the natural pressure on the fluids in the formation. Under this condition some of the drilling fluids will tend to enter permeable formations. The depth of entry of whole mud into a reservoir rock is usually small and varies with pore size and the bridging properties of the mud. Once the pores are bridged, the filter cake builds up on this bridge as a result of filtration. This process continues, with the total volume of filtrate being proportional to the square root of time if the filter cake is undisturbed. Naturally, the abrasive action of the drill bit and pipe will limit the maximum thickness. The rate of filter invasion and increase in thickness of the filter cake are a factor of filter-cake permeability and thickness. Therefore, the build-up is a function of the mud properties and not a quantitative measure of either permeability or porosity of the formation. No filtration occurs, and therefore no filter cake is formed on the wall of the borehole, where impermeable rocks are penetrated. Mud solids are found in a concentration of two or three times to as much as thirty to forty times their concentration in the mud. Consequently, the filter cake formed by a mud containing iron-oxide powder will be proportionally high in magnetic susceptibility. This phenomenon is very similar to the theory of operation of the microlog.

Because tracer methods rely on variations in the magnetic susceptibility of the filter cake, the contact magnetic susceptibility tool (Minimag) is most useful in such measurements. An example of a tracer-log study is shown in Figure 22-5. Other standard electric and radioactive logs are included, as well as permeability and porosity determinations from core analysis. During the drilling operations, circulation was lost when the bit was at 2030 feet. This circulation

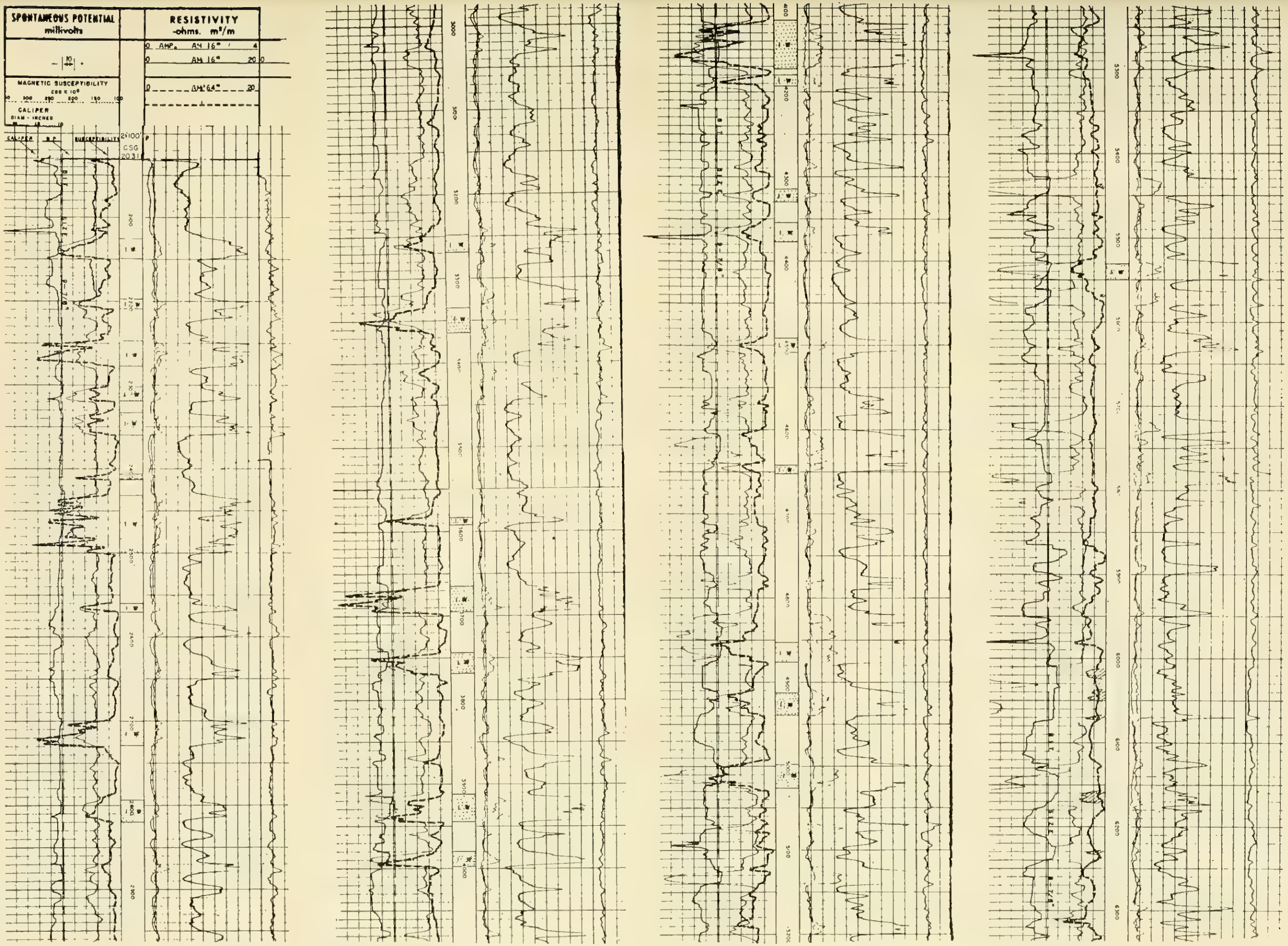

FIGURE 22-4. Magnetic susceptibility log comparison (Courtesy of Magnolia Petroleum Company).

loss point correlates with the spike labeled "C" on the Minimag log and is caused by the tracer-laden mud in a fault plane. The small anomaly labeled "D" is a result of variations in the natural susceptibility found in this shale member. Both magnetic logs were run after the tracer-laden mud had been displaced by mud devoid of tracer material. This displacement reduces the background and variations as a result of differences in borehole size or caliper. Unfortunately, there is no way of distinguishing between the natural susceptibility of formations and the artificial susceptibility of the mud cake from a single log. Therefore, background or control logs are necessary to determine if the background is negligible or consistent enough so that anomalous zones on the tracer logs can be qualified. As an aid, the tracer concentration is made high enough that it overrides typical variations in formation susceptibility. Consecutive logs can be run to show the build-up of cake in the anomalous areas.

Tracer logs of this type are unique in that they do not depend on the electrical properties of the formation and drilling fluids as required in electric logging. Therefore, tracer logs can be made in oil-base muds or muds of either very high or very low conductivity that would prevent the use of electric logs.

The magnetic susceptibility of rock containing iron is high compared to that of most sedimentary rock. Therefore, the use of this log in iron-ore evaluation would appear to be attractive. However, to date only experimental logs of this type have been made. It is believed that, with core control to establish calibration, it will be possible to make iron-ore assays in the borehole.

The magnetic susceptibility log is not affected by the conductivity of borehole fluid, whereas the induction conductivity component of the log is affected. The mono-coil instrument as described has no shaping or focusing of the field, and therefore the zone of influence is restricted to approximately two times the length of the sensing coil. Because of this effect, the conductivity log is best in muds having a resistivity of two ohmmeters or more. Conductivity logs from such an instrument are particularly advantageous in high-resistivity muds, such as oil or oil-base muds, or in open-hole logging where conventional resistivity logging methods are poor.

TOTAL FIELD LOGS To date, measurements of total field in the borehole have been only experimental. The complexity of the equipment has restricted its use to depths less than 3000 feet. In rock of low susceptibility, there is little character to the log. However, in zones of high susceptibility, the total field log indicates the polarization or field effect at some distance from the body, as well as the shielding effects of the body when it is penetrated. Such a log should have utility in detecting nearby deposits, if iron ores are not necessarily cut by the test hole.

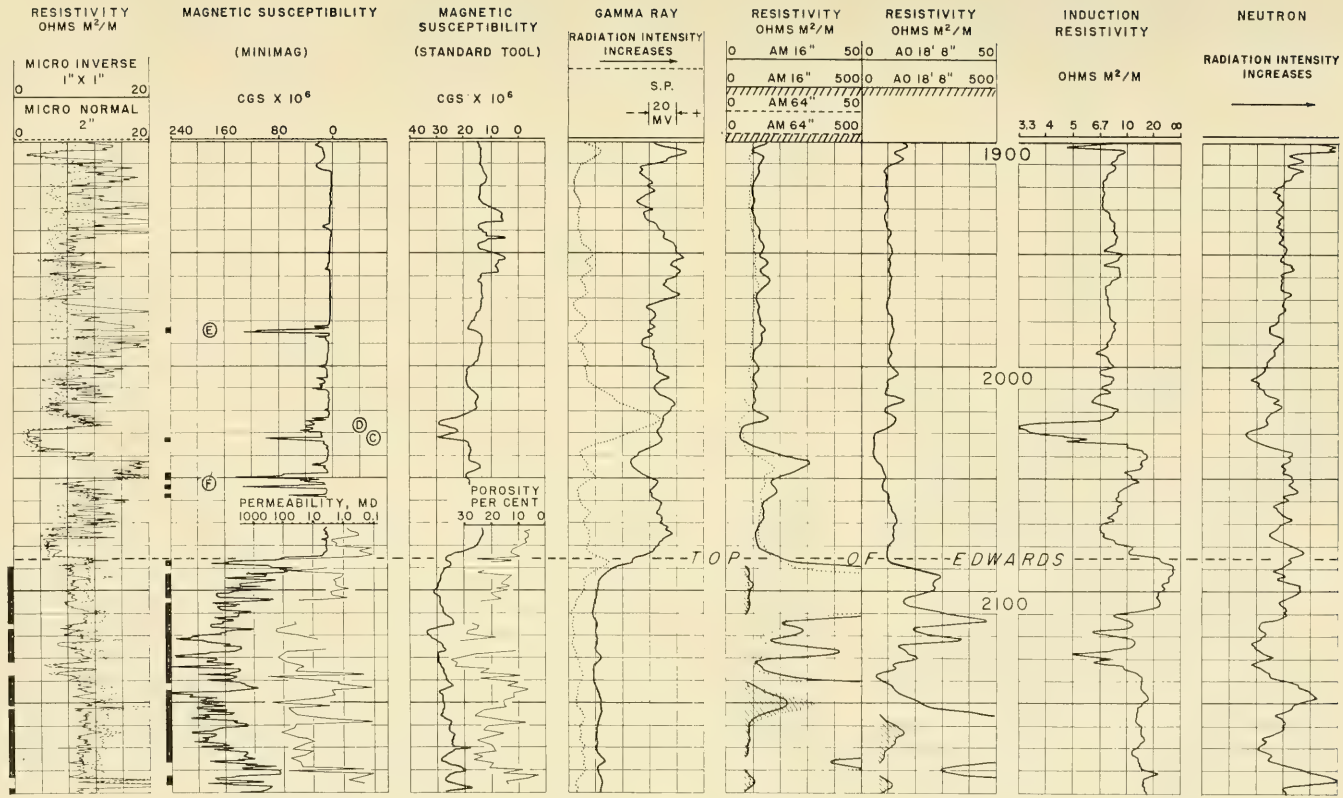

FIGURE 22-5. Tracer log comparison (Courtesy of Magnolia Petroleum Company).

SUMMARY

Magnetic susceptibility logs can be made as easily as an electric log. The logging speed is limited only by the limitations of hoists and recorders. Logs can be obtained in conventional oil- or water-base muds as well as in open hole. Logs have considerable character and exhibit good reproducibility. Magnetic susceptibility is an independent rock property and is controlled primarily by the iron content in the rock. Natural magnetic properties are easily correlated, and magnetic horizons have been correlated over considerable distances where other logging methods gave poor correlation. The use of magnetic tracers in drilling fluids has made possible the evaluation of filter cake build-up and has permitted permeable zones as well as zones of lost circulation to be detected. The magnetic susceptibility log in conjunction with the total field log has given control information for interpretation of surface magnetometer surveys.

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Patent No. 2,535,666.

Part Four

SUBSURFACE STRATIGRAPHIC AND STRUCTURAL INTERPRETATION

Chapter 23

STRATIGRAPHIC CORRELATION

L. W. LeRoy

Correlation of stratigraphic units permits establishment of formational sequences, evaluation of contemporaneous and noncontemporaneous deposits, recognition of unconformities, reconstruction of paleotectonic fabrics, and delineation of sedimentational patterns.

During the past 20 years many new ideas, methods, and approaches in stratigraphic geology have increased the accuracy with which stratal and paleontological units can be correlated. The introduction of statistics into stratigraphic geology has been responsible, partly, for this new thinking; however, much more remains to be done in the way of integrating and interpreting accumulated stratigraphic data.

In some areas, correlation of stratigraphic units is difficult, if not impossible; in others, no serious problem exists. To treat adequately this range of situations, the geologist must be familiar with the fundamentals of correlation and able to analyze stratigraphic conditions so as to determine what procedure or procedures (and their limitation) are applicable in solving them.

STRATIGRAPHIC UNITS

Before the correlation of deposits is attempted, it is essential that stratigraphic units be defined accurately. Schenck and Muller (1941) recommended that continued use be made of three types of stratigraphic units as a basis for correlation: (1) lithogenetic (rock), (2) time-stratigraphic (time-rock), and (3) time.

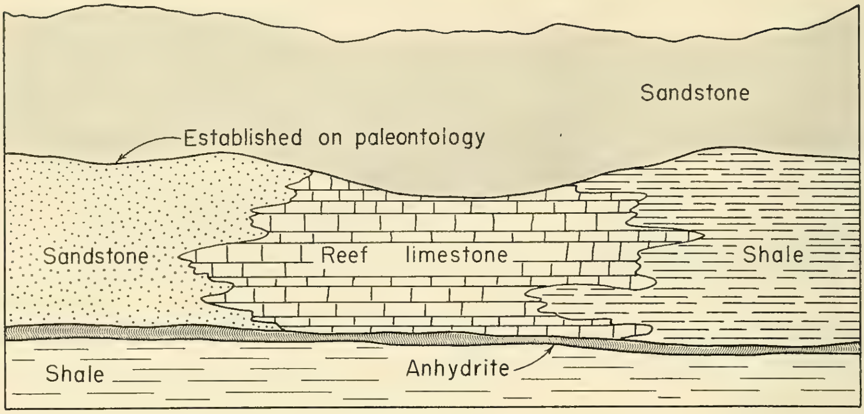

FIGURE 23-1. Time-stratigraphic unit. The sandstone, limestone and shale between times surfaces T_1 and T_2 constitute a time-stratigraphic unit whose upper boundary is defined paleontologically and whose lower boundary involves an anhydrite bed. To establish contemporaneity of these three lithologies (facies) within the time-stratigraphic unit requires careful surface and subsurface mapping, particularly in areas of interfingering.

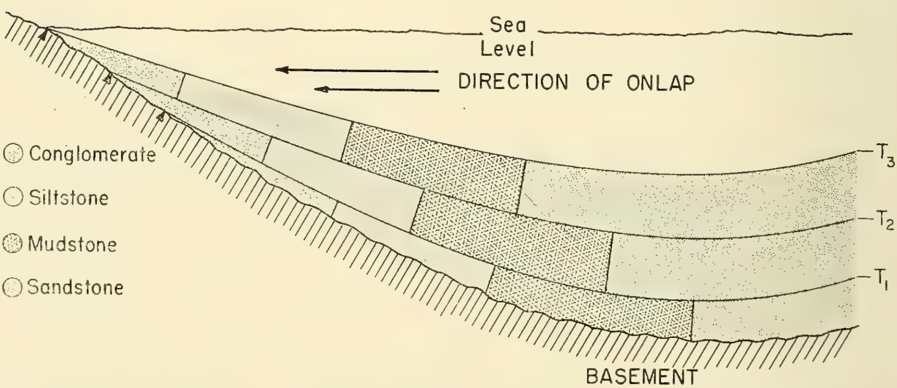

FIGURE 23-2. Relationship of time-stratigraphic and lithogenetic units. Depositional onlap as illustrated results from a transgressive sea. In this sketch the base of the sedimentary section is marked by an unconformity which becomes progessively younger towards the apex of the sedimentary wedge and thus does not represent a true time surface; however, under certain conditions, unconformities do correspond to time surfaces. Assume that time surfaces T_1, T_2, and T_3 have been established paleontologically from the center of the basin to a point (short arrows) where they intersect the basement. The four lithologic facies (conglomerate, siltstone, mudstone, and sandstone) between T_1 and T_2 constitute a time-stratigraphic unit. The same applies for deposits between T_2 and T_3. The deposits between the unconformity and T_1 is not a time-stratigraphic unit because the unconformity surface is time transgressive.

Lithogenetic or rock units involve specific rock masses such as the group, formation, tongue, and bed-units with which the geologist is concerned primarily in his mapping programs.

Time-stratigraphic units are represented by deposits that have accumulated during a specific interval of geologic time. The boundaries of these units are time surfaces, which are established most commonly on paleontological evidence; however, these surfaces may be delineated sometimes by unconformities. A time-stratigraphic unit frequently contains, within its boundaries, various types of deposits, (sandstone, reef limestone, and shale) as shown in Figure 23-1 between T_1 and T_2. Time stratigraphic units may transect lithogenetic units, as illustrated in Figure 23-2. Hedberg (1948) states that "it is desirable to be able to express as a time-stratigraphic unit the sediments equivalent in age to the same time scope of any recognizable feature of sedimentary rocks which may be useful as a stratigraphic measuring stick."

Time units (Era, Period, and Epoch) involve segments of geologic time and are related to the lithologic and paleontologic aspects of a stratal sequence only indirectly. To define these units it is necessary, first, to evaluate the total aspect of lithogenetic units. Next, the boundaries of the time-stratigraphic units are delineated, and they, in turn, permit erection of the time units.

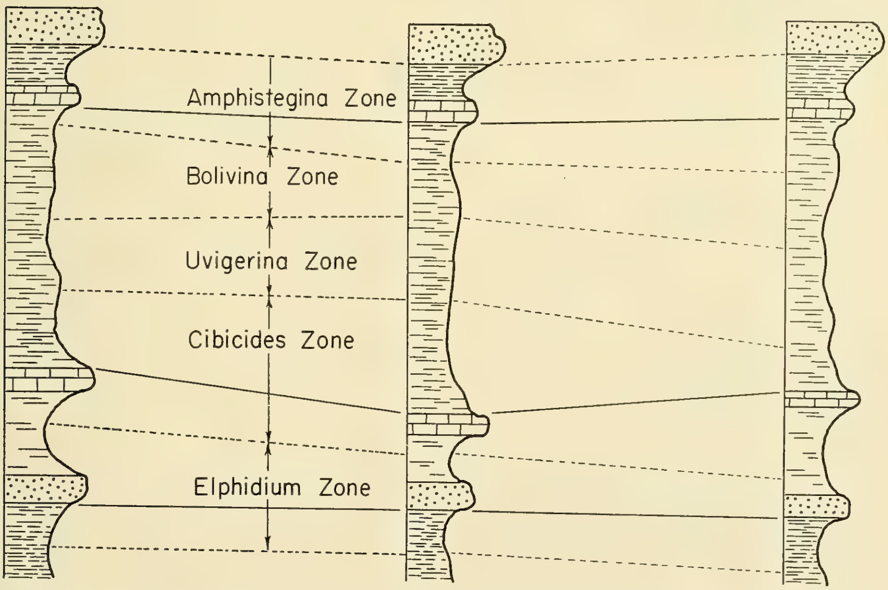

FIGURE 23-3. Biostratigraphic zonation. The boundaries of biozones frequently do not coincide with lithologic boundaries. The paleontologist is concerned, primarily, with the *former* and the field geologist with the *latter*. Paleontologic and lithologic unit relationships should be properly evaluated and integrated in all correlation investigations.

The definition of biostratigraphic units (biozones) is based on the paleontological aspects of the section. Figure 23-3 demonstrates a common relationship between boundaries of biozones and lithogenetic subdivisions. It is not uncommon for the boundaries of these units to be nonconformant. Biozones are recognized by a single species or genus, a simple or complex assemblage, or an evolutionary development of paleontologic elements. Biozones play a major role in establishing boundaries of time-stratigraphic units.

A more detailed account relating to stratigraphic units is given by Ashley and others (1932) and Moore (1947).

SPACE-TIME CONCEPT IN CORRELATION

The correlation of stratigraphic units requires an understanding and practice of the space-time concept, which involves three spatial components and one time component. Such variables as composition, texture, color, porosity, permeability, thickness, and paleontology must be evaluated through time and along the space components in order to establish the contemporaniety or noncontemporaniety of deposits. The concept must be considered, also, during evaluation of tectonic problems. Figure 23-4 demonstrates the lateral and vertical variations of three lithologies (facies) in space within a time-stratigraphic unit.

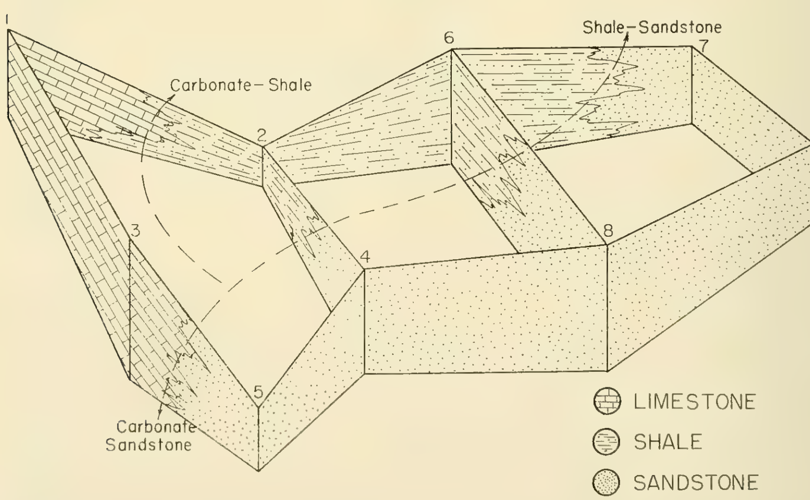

FIGURE 23-4. Panel diagram showing space relationships of facies changes of a time-stratigraphic unit. Dashed lines indicate the approximate lateral extent of the major lithofacies. Data shown on this panel may be represented also by isopach and lithologic percentage or ratio contours. Stratigraphic panels permit rapid space evaluation of depositional relationships.

FACIES FACTOR IN CORRELATION

Moore (1949) defines a sedimentary facies as an "areally segregated part of differing nature belonging to any genetically related body of sedimentary deposits"; stated somewhat differently—any areally segregated part of a stratigraphic unit (lithogenetic, time-stratigraphic, time). The relationships of these parts must be analyzed lithologically and paleontologically in four dimensions before correlations are of value. Twenhofel (1953) emphasizes this point by saying . . . "when two deposits of the geologic column have been found to hold pretty much the same organisms, it has been assumed that the two deposits have synchronous relations. It is equally, if not more valid, to assume that the two deposits were laid down under similar environments and may actually be somewhat different in age . . .".

The facies principle is not always recognized nor practiced by many geologists. As a result, serious errors have been made in correlating stratigraphic

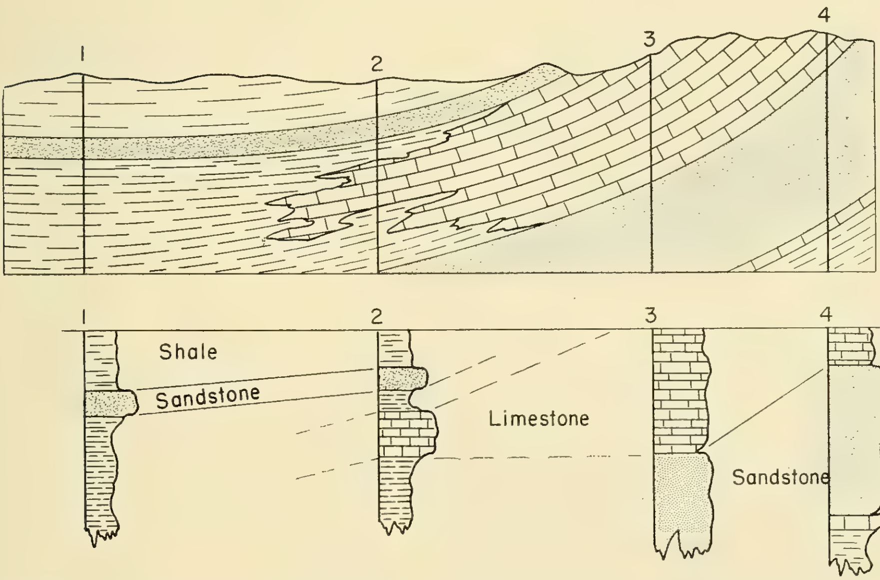

FIGURE 23-5. Facies correlation. This cross section shows a limestone grading down dip into a subsurface shale. The interval involving this lateral change is bounded by two blanket sandstones. Four wells have been drilled, and their penetrated sections are shown by the stratigraphic columns. As indicated by these columns, it would be difficult to establish the true lateral lithic relationship on the basis of only well data. To prove or disprove this relationship would require the drilling of several more wells in the interfingered part of the section; for example, the limestone in Well 2 does not represent the same time interval as that in Well 3; it is equivalent to only the middle part of that penetrated in Well 3. The absence of the limestone in Well 1 could be accounted for by faulting or unconformity if the lateral lithologic relationship were not known.

units that are separated widely, geographically and stratigraphically. Figure 23-5 illustrates a major down-dip facies change—limestone to shale—with the latter present only in the subsurface. Data from wells 1, 2, 3, and 4 would suggest a correlation as shown by the columnar sections; however, this correlation fails to represent the true lateral equivalency relationships of the limestone and shale facies. Additional wells between 1 and 2 and between 2 and 3 would improve the overall correlation. Such a facies change could have resulted from tectonic adjustments in the source and depositional areas, from geomorphic changes and climatic fluctuations, and from changes in temperatures, pH values, currents, and depths of the water under which the deposits accumulated. To accurately evaluate such changes, one should prepare various types of stratigraphic maps (see p. 449). Once the facies relationships have been determined, it then becomes less difficult to unravel the tectonic and sedimentational history of a region, the normal stratigraphic sequence, and the trend of potentially petroliferous areas. The results obtained from facies studies are no more accurate than the correlations of the stratigraphic units on which they are based.

CORRELATION MARKERS The recognition and the definition of lithologic, paleontologic, and seismic markers in controlled stratigraphic sequences are of utmost importance in all correlation work. These markers, including limestone, bentonite, coal or lignite, anhydrite, concretions, chert, glauconite, or any other lithic or paleontologic types,

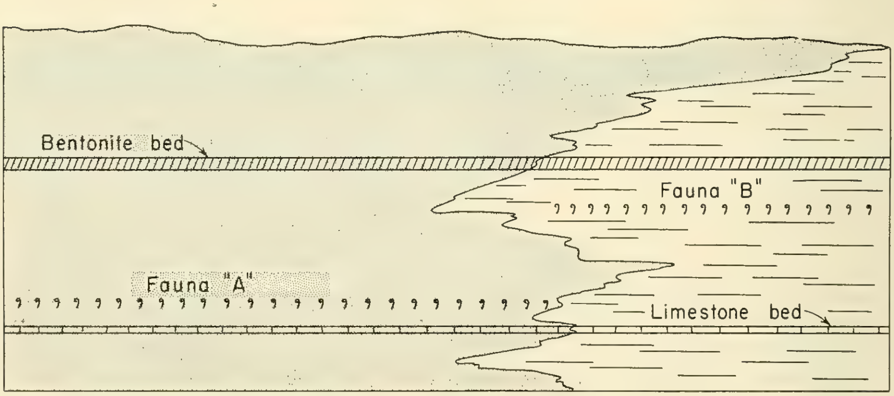

FIGURE 23-6. Marker beds. The bentonite and limestone marker beds, common to the two lithic facies, aid materially in establishing equivalency of the facies. Fauna A and B are facies assemblages that contribute little to establishing the lateral equivalency of the dissimilar deposits. They are, however, extremely important in paleontologically subdividing their respective facies.

must be more or less laterally continuous as well as restricted vertically. Unconformities of local and regional extent have often served as correlation datums.

Every attempt should be made to select marker beds common to more than one facies, as for example, the bentonite and limestone beds shown in Figure 23-6. Facies fauna A and B in this figure can be used only locally. Some of the more common paleontologic markers include foraminifera, ostracodes, fish teeth and scales, pollen, conodonts, and macrofossils.

MAGNITUDE OF CORRELATIONS

Correlations may be of local, regional, interregional, or of intercontinental magnitude. Local correlations, for example, within an oil field or in a small depositional basin, range from simple to complex. If stratal and paleontological units are extremely discontinuous, proving contemporaneity or noncontemporaneity of dissimilar lithologies and faunas is difficult.

Regional correlations between basins of large provinces, such as the Rocky Mountain Province, may be difficult, particularly if each basin has had a different sedimentational and structural history. Interregional correlations, as between sections of the Gulf, Pacific, and Atlantic coasts, can be determined only approximately—mainly on the basis of paleontology. Intercontinental correlations involve those between continents, and under no circumstance can the lithologies of the sections be considered in this type of correlation problem.

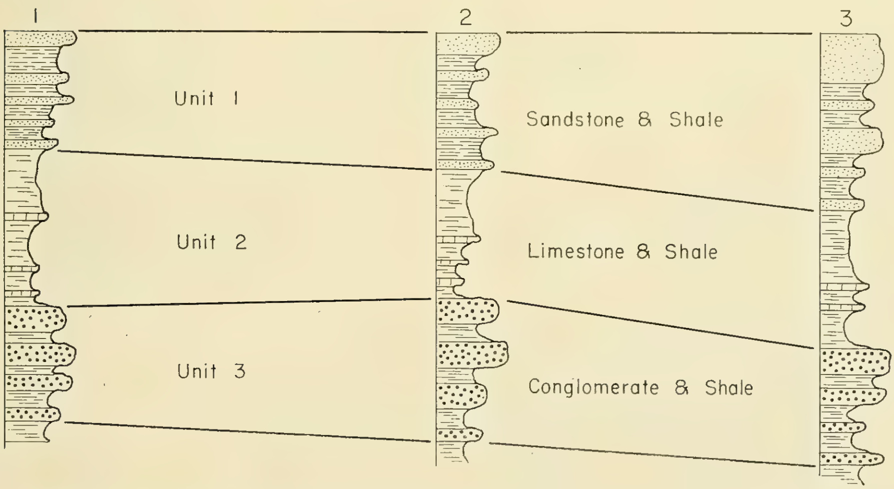

FIGURE 23-7. Definition of major stratigraphic units. In all correlation work it is important first to define the major lithologic or paleontologic units of the section as, for instance, Units 1, 2, and 3. Following this subdivision, detailed correlations may be established within the units.

Paleontology is the primary basis for these correlations. In general, it may be said that the greater the distance between stratigraphic sections, the more difficult and uncertain the correlation.

GENERAL TO DETAIL PROCEDURE IN CORRELATION

Before an attempt is made to unravel geologic problems, whether they involve structure, paleontology, or stratigraphy, it is sound practice to outline, first, the broad aspects of the problem — in other words, generalize the situation. Once a problem is generalized, the details within its boundaries then can be investigated. Following the detail stage, the problem should be re-generalized and re-detailed periodically. Figure 23-7 serves as a basis for this procedure. Let it be assumed that stratigraphic sections 1, 2, and 3 have been measured, sampled, and accurately described lithologically and paleontologically and that the major lithic units (1, 2, 3) of the sections have been defined. Correlation of the minor beds within each major unit is the next step. This procedure is extremely applicable also in correlating mechanical well-log profiles—the entire profile should be examined before the minor peaks and valleys between major boundaries are evaluated.

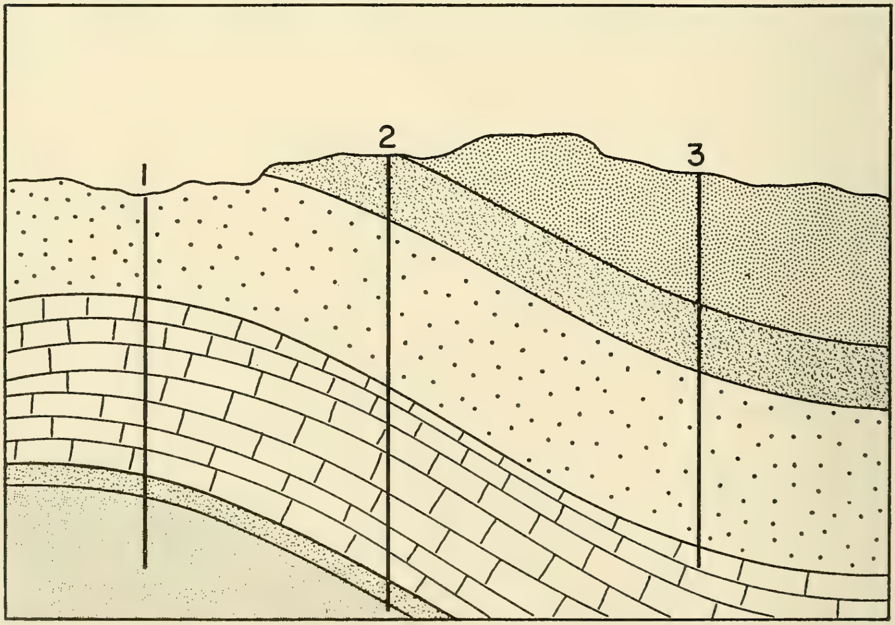

FIGURE 23-8. Simple structure and stratigraphy. Correlation of stratigraphic units in the three wells should offer no difficulty provided sufficient well samples and cores were available.

FACTORS CONTROLLING CORRELATION INVESTIGATIONS

Some of the more critical factors controlling the solution of correlation problems are the following:

Lateral Continuity of Deposits

The more uniform the lithology and paleontology of a stratigraphic sequence, the less difficult the correlation of surface and subsurface units (fig. 23-8).

Structural Complexity of Section

In areas where the section is highly folded and faulted, and unconformities are present, correlations are frequently complicated—at least, until a normal stratal sequence has been established (fig. 23-9 .

Availability of Basic Data

In some areas stratigraphic data are extremely meager or absent. In such cases the geologist is greatly handicapped and must bide his time until data become available.

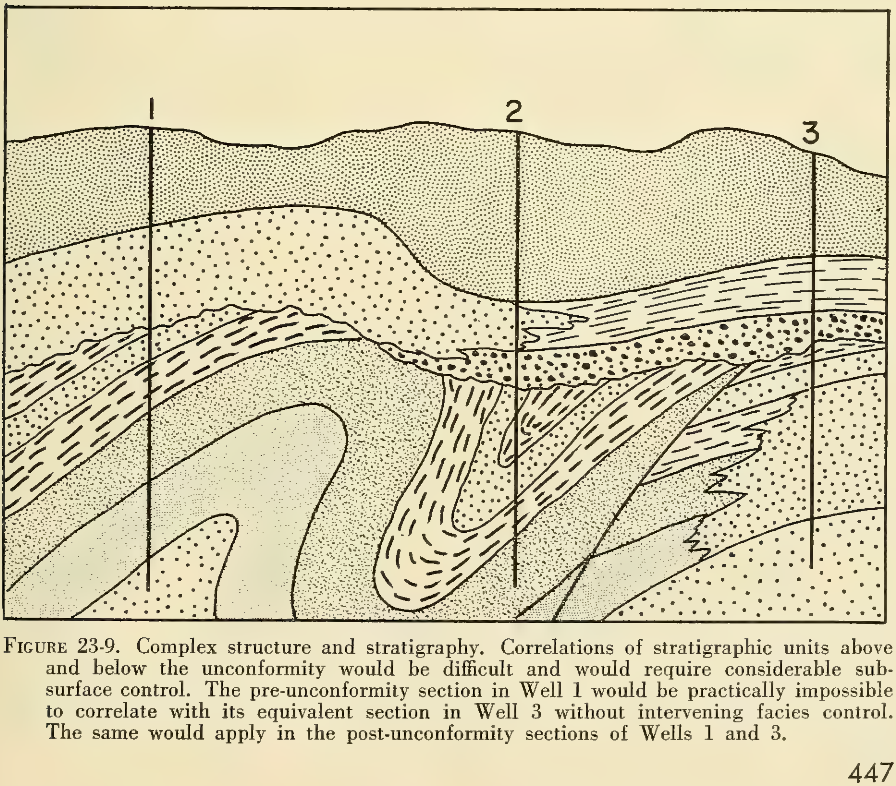

FIGURE 23-9. Complex structure and stratigraphy. Correlations of stratigraphic units above and below the unconformity would be difficult and would require considerable subsurface control. The pre-unconformity section in Well 1 would be practically impossible to correlate with its equivalent section in Well 3 without intervening facies control. The same would apply in the post-unconformity sections of Wells 1 and 3.

Time and Cost

Some oil companies follow an ultraconservative attitude in their stratigraphic programs and make every attempt to reduce or even eliminate coring, taking ditch samples, or running an electrical log. These "savings" frequently result in failure to place a well on production or loss of profitable leases. On the other hand, many companies spend great sums in obtaining basic stratigraphic information.

Quality of Personnel

For one to become familiar with the various methods of correlation—their uses and limitations—requires time, experience, and integrated reasoning A company having young, inexperienced geologists must expect correlation errors; therefore, every attempt should be made to give these men intense and adequate training before allocating them responsibilities in correlation.

METHODS OF SUBSURFACE CORRELATION

All methods and techniques listed in Figure 23-10 are applicable to correlating subsurface stratigraphic units; but to apply any one of them beyond their limitations generally initiates poor results. Each method must be considered only an integral part of the total correlation procedure.

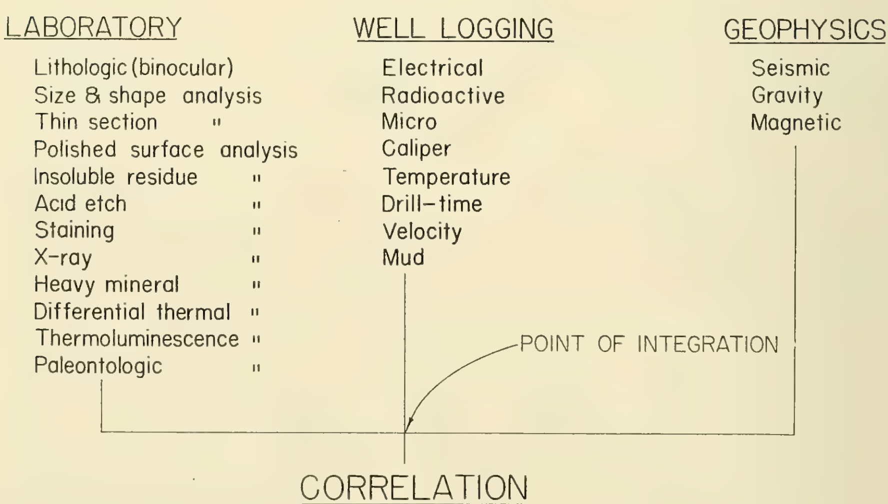

Figure 23-10. Procedures applied in correlation of strata. Some correlation problems require a combination of procedures; others may involve only one to obtain favorable correlation results.

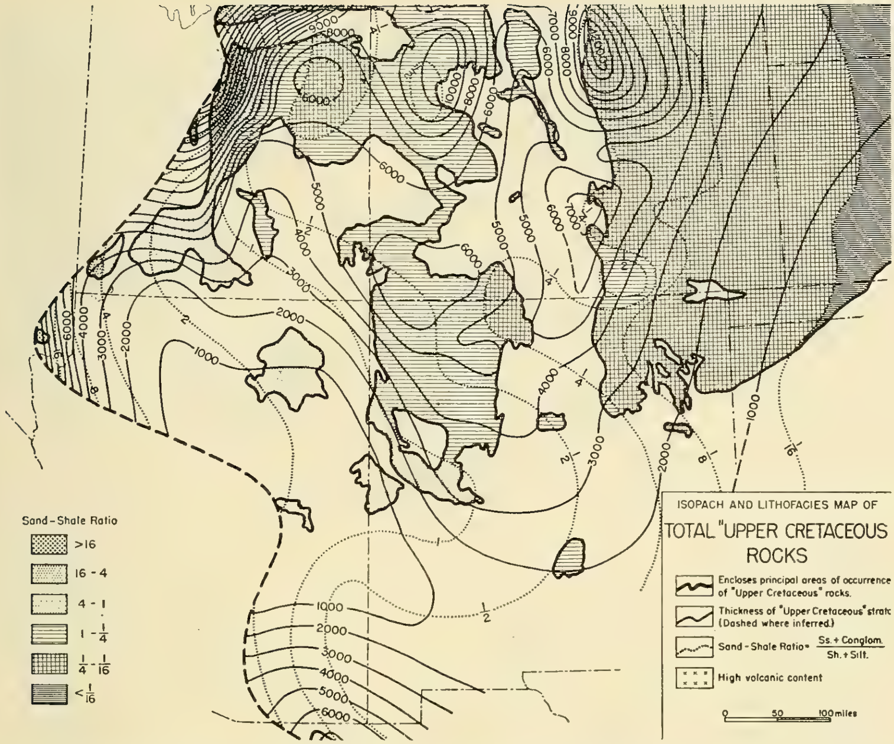

FIGURE 23-11. Isopach and sand-shale ratio of the total "Upper Cretacious" rocks. (Krumbein and Nagel, courtesy American Association of Petroleum Geologists).

STRATIGRAPHIC MAPS AND CORRELATION

During the past 10 years, great advances have been made in presenting stratigraphic data in the form of contour maps. Among the many leaders in this field of analysis are M. Kay of Columbia University, W. C. Krumbein, L. L. Sloss and E. C. Dapples of Northwestern University, E. M. Spieker of Ohio State University, E. D. McKee of the U. S. Geological Survey, and J. W. Low of The California Company.

The philosophy of preparing stratigraphic maps is based on the idea that *any stratigraphic variable* (color, texture, composition, thickness, etc.) *that can be expressed numerically can be contoured.* The more common lithofacies maps include the isopach, clastic ratio, lithic percentage, and lithic ratio. Convergence and paleogeologic maps have played a major role in regional and local stratigraphic studies. Maps showing biologic aspects of stratigraphic units are included, as well as those illustrating paleotectonic developments and trends. These maps permit improved interpretation of structural changes, evaluation of sedimentational history, and outlining paleogeographic patterns.

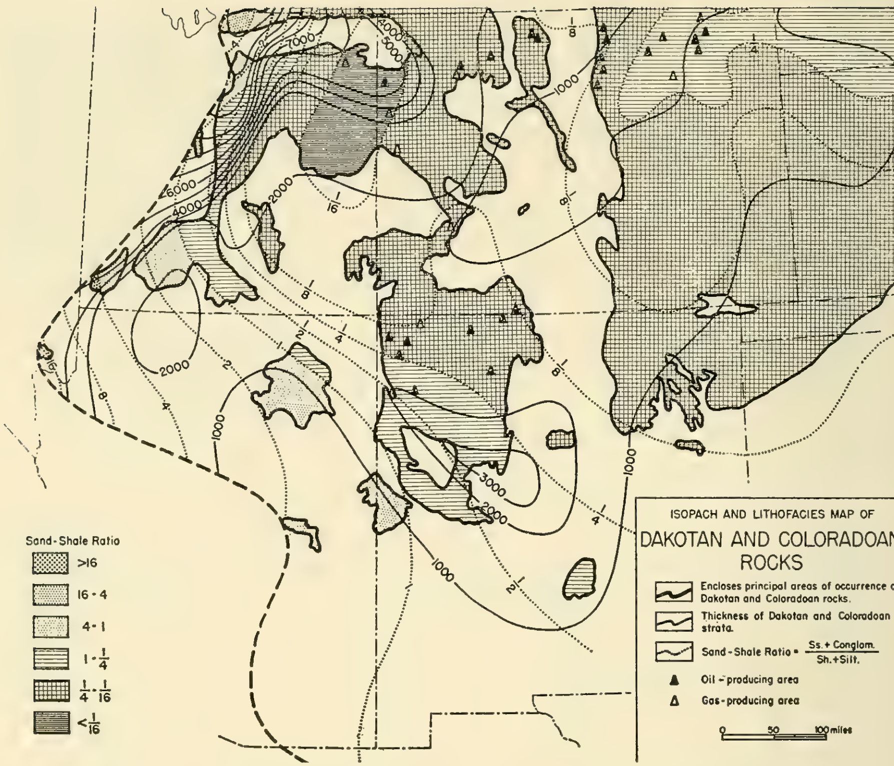

FIGURE 23-12. Isopach and sand-shale for the Dakotan and Coloradoan rocks (lower subunit of the section analyzed) (Krumbein and Nagel, courtesy American Association of Petroleum Geologists).

To initiate construction of a series of stratigraphic maps, the following procedure is recommended. Measure, describe, and sample, in detail, surface and subsurface sections; define the boundaries of stratigraphic units and establish their lateral equivalents; prepare the following maps: *isopach,* which is the basis for all subsequent stratigraphic-type maps; *lithofacies,* including clastic and non-clastic (percentage or ratio); *biofacies* (percentage or ratio of variables); and *tectofacies* and *paleogeographic.* When these maps are completed—then comes the stage of integration and interpretation of the data.

Figures 23-11, 23-12 are examples of typical maps prepared by Krumbein and Nagel (1953) during their stratigraphic studies of the Cretaceous of the Rocky Mountain region. Basic data for this study were obtained from many surface and subsurface sections. The purposes of the maps were "to present the broad pattern of thickness and lithologic variation in the Upper Cretaceous and to introduce methods for expressing the vertical variability, as well as the lateral variation in the section." After proper integration of such maps, much may be learned of the tectonic and sedimentational history of the region. These maps could not have been prepared until fundamental stratigraphic units had been defined and correlated.

DIFFICULTIES OF CORRELATION

Some of the more common difficulties encountered in correlation work are: (1) discontinuity of stratigraphic units; (2) structural complexity; (3) lateral variations in thickness, lithology, and paleontology; (4) poor development or absence of marker beds; (5) presence of unrecognized unconformities; (6) limited number of control sections; (7) multiplicity of lithogenetic and time-stratigraphic nomenclature; (8) erroneously compiled data; and (9) lack of experienced personnel assigned the problem.

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Chapter 24

SUBSURFACE MAPS AND ILLUSTRATIONS

Julian W. Low

PREPARATION OF SUBSURFACE DATA

The term subsurface map may be somewhat confusing in that nearly all types of both surface and subsurface maps display features that are actually concealed at the surface of the ground by soils, alluvium, and other types of overburden. The geologic formation or horizon contoured on a surface-structure map may lie beneath other formations over the greater part of the map area, as shown in the cross section in Figure 24-1. In this figure, points 1, 2, and 3 are outcrops of the datum horizon where direct instrumental observations can be made. Point 4 is an outcrop of bed *C*, stratigraphically below the datum, and 5, 6, 7, and 8 are outcrops of beds *B* and *A*, stratigraphically above the datum. Control points *a*, *b*, *c*, *d*, and *e*, are computed from instrumental observations obtained on the outcrops. The position of the datum surface from 1 to 2 and 3 to *e* is restored above the actual surface of the ground, and at all other places the datum is covered by other formations.

Figure 24-2 is a subsurface cross section. Neither the datum nor the two key beds *A* and *B* crop out at the surface. The control points, *a*, *c*, and *e*, are determined from the logs of wells which penetrate the datum bed. Control points *b* and *d* are computed from the drilled points on key bed *A*. The similarities in the section shown in Figures 24-1 and 24-2 are obvious. Indirect methods are used in the construction of both; yet one is a surface section and the other a subsurface. The principal difference in these sections and in surface and subsurface maps is that the surface map or section is constructed from surface data; that is, from outcrops. The subsurface section or map is constructed from data supplied by wells that have penetrated recognizable formations.

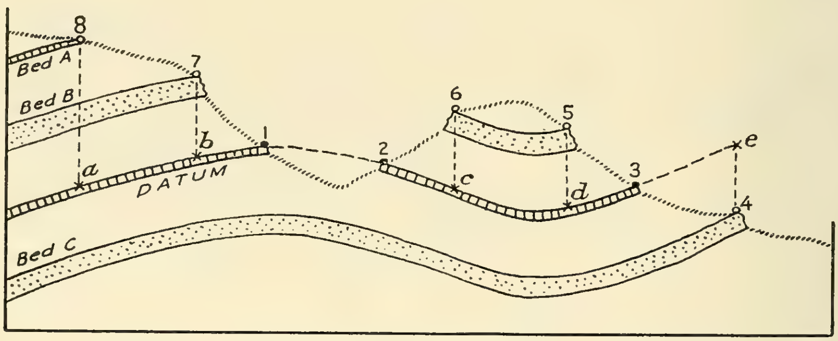


FIGURE 24-1. Geologic cross section compiled from surface data.

The subsurface map can be only as reliable as the data used in its preparation. In surface mapping it is usually possible to observe the structural or stratigraphic behavior of formations over a considerable area around an instrument or rod station. The geologic interpretation of soils, topography, plant ecology, springs, and other natural conditions, can aid materially in bridging over areas where the bedrock formations are concealed from direct observation. In contrast to the areal control available on the outcrops, there is only point control for subsurface work. For this reason, the data from wells must be prepared with considerable care.

Reduction to Datum Elevation

The elevation on the datum bed is the algebraic difference between the surface elevation of the well and the drilled depth to the datum. Thus, if the surface elevation is 5000 feet and the depth to the datum is 4000 feet, the datum elevation is 1000 feet. If the depth is 6000 feet, the datum elevation is minus 1000 feet (1000 feet below sea level).

If the drill hole is crooked, the apparent vertical depth to the datum will be either too great or too small. Figure 24-3*A* shows a hole that has drifted downdip and penetrated the datum at point *a*. If one uses the actual drilled interval from the surface to point *a* and the surface location of the well, the datum would appear to be at *b*. Although the actual dip is to the west, the crooked hole produces an erroneous effect of east dip. In *B* of Figure 24-3 the hole has drifted

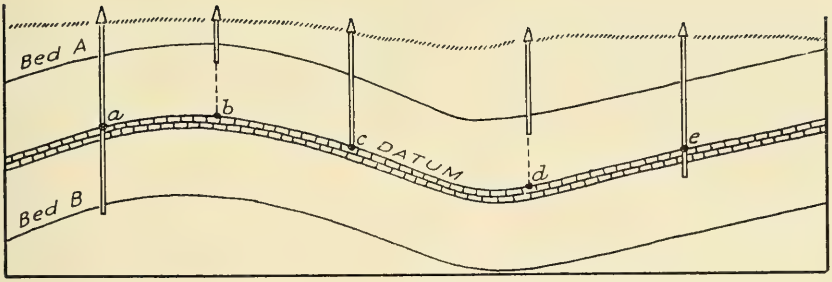
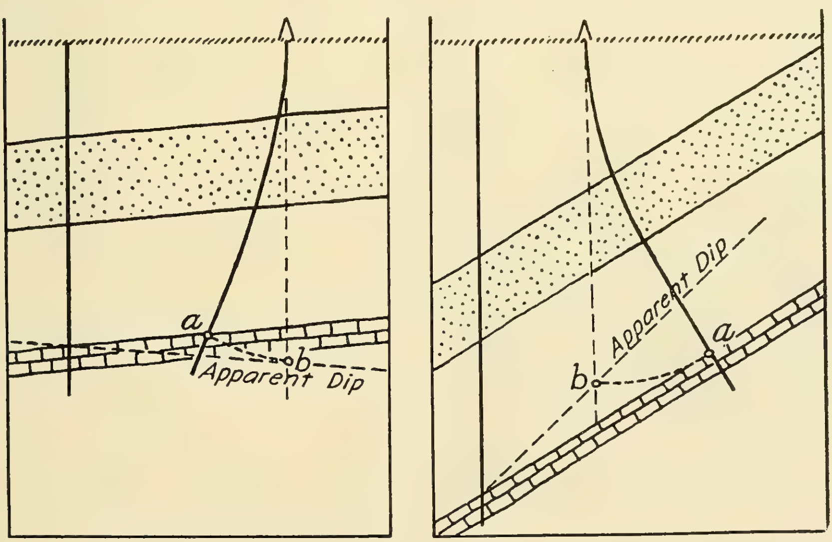


FIGURE 24-2. Geologic cross section compiled from subsurface (well) data.

in a direction up the dip. In this instance, the actual drilled interval is less than the verticle depth of the datum bed. The effect is an apparently steepened dip between the two wells.

Unless a directional survey has been made, it is impossible to adjust the log of a crooked hole to obtain a correct datum point.

Dips or dips and strikes determined from cores can aid the subsurface geologist greatly; but they can also lead him far astray in his interpretations. It is hazardous to use core dips indiscriminately in subsurface mapping. The core dips should always be adjusted by means of hole deviation or directional surveys when available. When straight-hole determinations have not been made, core dips should be used with caution. Figure 24-4*A* shows a straight hole



A *B*

FIGURE 24-3. Effects of crooked holes on datum elevations and interpreted dips.

drilled on a sharply folded anticline. Both core dips and drilled stratigraphic intervals increase with depth. Figure 24-4*B* shows a hole that drifts down the dip on a monocline, with erroneous increases in core dips and drilled intervals similar to those on the flank of the anticline. Deviation surveys used in conjunction with the core dips reveal the true subsurface conditions so that the formations can be correctly mapped.

Figure 24-5*A* shows a gradual thinning of two formations in the central portion of the stratigraphic succession. Core dips from the two wells would show a gradual increase with depth through the converging portion of the section. Dips below the thinning portion are steeper than those above, but remain constant as deep as the strata are parallel.

The two wells represented in *B* of Figure 24-5 would suggest a similar convergence in the drilled intervals. There is one important difference, as shown by core dips: the dips above and below the inclined part of the hole are the same. Core dips from the straight hole on the right are constant throughout the apparently converging interval. Thus, where regional conditions are well known through an adequate distribution of subsurface control, it is sometimes possible to infer correctly that a portion of one hole is crooked, even though a deviation survey has not been made.

It is outside the scope of this chapter to describe in detail the causes and effects of crooked holes. The preceding examples are only a few of countless

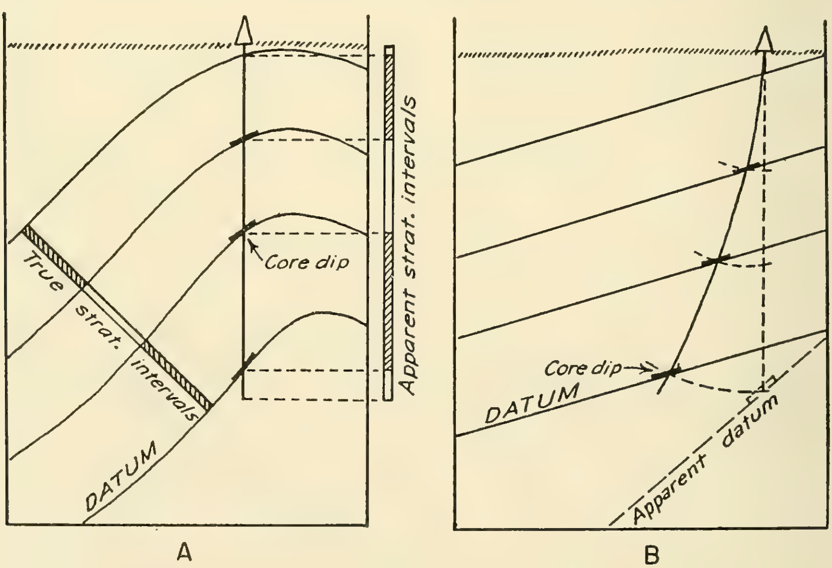


FIGURE 24-4. *A*—Core dips and stratigraphic intervals increasing with depth on sharply folded anticline. *B*—Migration of hole downdip resulting in core dips and stratigraphic intervals similar to those in *A*.

conditions that test the ingenuity of the subsurface geologist. These examples will serve to show that all data obtained from wells, such as formation tops, dips, thicknesses, and others, are subject to critical examination and balancing, one against the other, before they may be used with confidence in mapping.

KINDS OF MAPS

Structural Contour Maps

There is no fundamental difference between a surface and a subsurface structural map. Both attempt to show by means of contours the configuration of a selected continuous stratigraphic horizon, commonly called the datum or datum horizon. As stated earlier, the principal difference is in the kinds of data used in construction.

The subsurface structural map is almost or quite dependent on wells for the necessary control. Ordinarily, the elevations on which the contours are drawn are obtained by the simple process of subtracting the depth to the datum horizon from the surface elevation of the well, the latter being established at the point from which depth measurements are made. This point in most cases is the rotary table or the rotary bushing of the drilling rig.

The block diagram *A* in Figure 24-6 illustrates an anticline that is typically eroded in the surface formations. In the same figure the block is separated to show a buried major nonconformity, the presence of which is suggested nowhere in the surface geology.

The structural contour map in Figure 24-7 is based on surface elevations and dips in the area shown as a block diagram in Figure 24-6. The structural map in

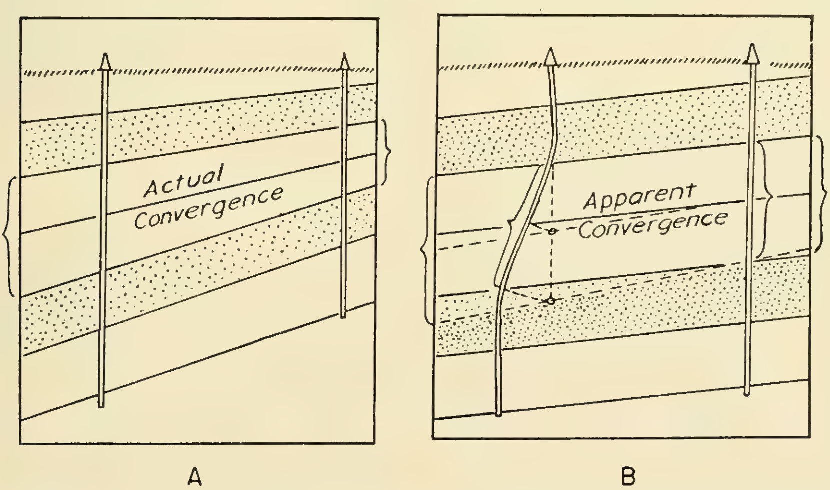


FIGURE 24-5. *A*—Actual convergence of section. *B*—Apparent convergence as a result of crooked hole.

Figure 24-8 is constructed solely on data supplied by the 24 wells that penetrated the Paleozoic formations below the Jurassic unconformity. The block diagram shows four of these wells, three of which are in the vertical planes of the block.

In the central part of the Cambrian structure map, the actual datum, which is the top of the Cambrian, has been destroyed by pre-Jurassic erosion. This is shown by the fact that wells 8, 10, 16, 18, and 19 entered the Cambrian directly beneath the Jurassic without first penetrating the systems that overlie the Cambrian toward the edges of the map. Although the contours within this area of truncation are drawn to the elevations at which the Cambrian is encountered below the unconformity, they do not represent the true structural configuration of the strata. In order to do so, it would be necessary to reconstruct the original thickness of Cambrian throughout the area of truncation and raise the elevations accordingly. Even this process cannot be employed in the center of the area where Cambrian beds are absent, for there is no method by which the depth of erosion of the pre-Cambrian rocks can be determined. Close approximations can

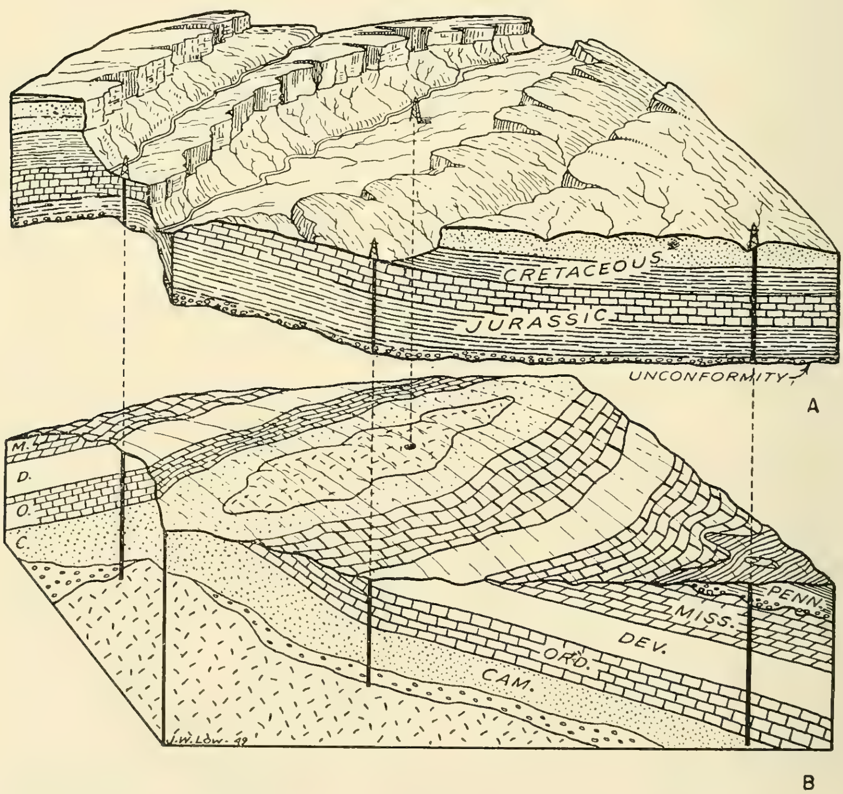


FIGURE 24-6. Typical eroded anticline involving a major unconformity in subsurface.

be attained, however, if there is sufficient well control for constructing a Cambrian isopach map.

Disconformities are frequently not recognizable in well samples or on electric and radioactivity logs; therefore, so-called regional structural maps may not truly represent the regional structure. The departure of the contouring from that of a true structural picture is controlled by the thickness of section eroded away, the relief of the unconformity, and the average rate of regional dips. This discrepancy is greatest where the dips are low and the relief on the unconformity is relatively high. It is purely a matter of chance that certain wells strike the horizon of the unconformity at high points and others at low. Figure 24-9 shows an example where four wells fail to reveal the presence of a structure because the wells on the high part of the structure happened to strike locally low points on the unconformity, whereas those structurally lower encountered locally high points on the erosion surface.

Sometimes a subsurface disconformity can be recognized by the types or condition of the rocks in the drill cuttings; but commonly the sample work is not done with sufficient care to differentiate these materials, or the diagnostic materials may be absent at the particular point where the well was drilled. There are two principal reasons for contouring unconformities: one is that a vast amount of oil has been found in the zones of unconformities and directly

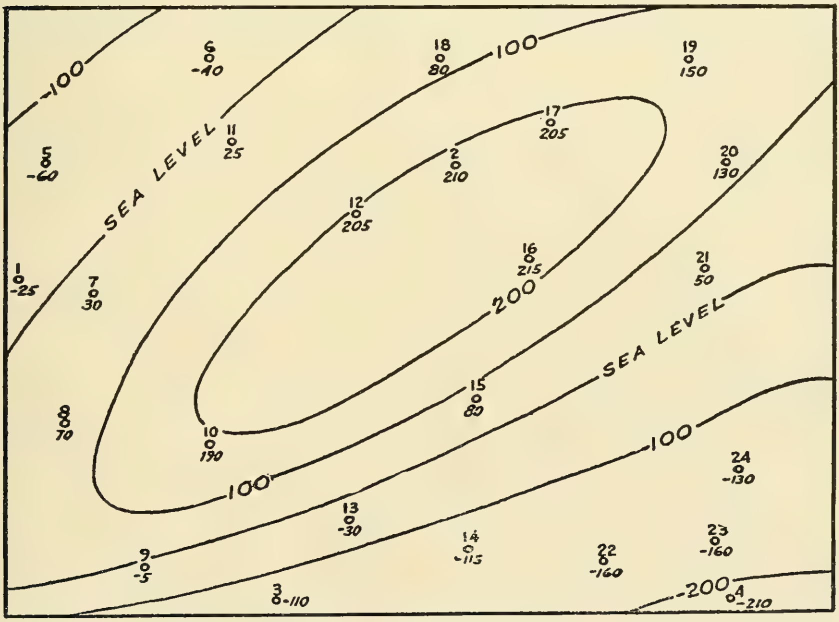


FIGURE 24-7. Structure contour map on top of Jurassic.

associated with them. The other is that in many regions the geologic section is lacking in stratigraphic horizons that can be traced continuously over wide areas; and, if the formation immediately under the unconformity can be recognized from well samples throughout large regions, it is only logical to select it as a regional mapping horizon. For example, the "top" of the Mississippian is commonly contoured in parts of the Midcontinent region despite the fact that it is an erosion surface, because it can be easily recognized in well samples and drillers' logs.

In the construction of subsurface structural maps of oil fields that have not been entirely defined, it is often of the greatest importance to work out carefully even minor details, such as the exact character of faulting, in order to avoid the drilling of unnecessary dry holes and to make certain that all potentially productive locations are tested.

The structure map in Figure 24-10 shows a partly developed oil field with a number of oil and gas wells and dry holes. A normal fault dipping to the southwest cuts across the southwest end of the anticline. The structural datum is the top of the producing horizon.

Although a fault is commonly represented on maps as a single line, a normal fault with a low-dipping plane invariably results in a zone where the datum surface is absent. This zone is called a datum gap. The breadth of the

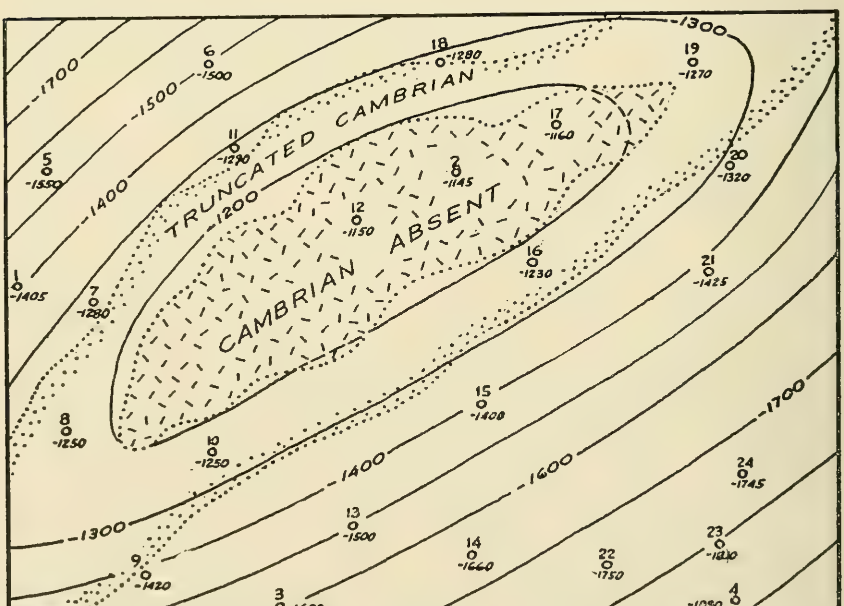


FIGURE 24-8. Structure contour map on top of Cambrian.

datum gap is determined by the degree of dip in the strata, the dip of the fault plane, the amount of throw, and the relationships between the dip and strike of the strata and the fault plane. The datum gap can be worked out on a subsurface structure map if there are sufficient datum points to control the general contouring of the structure and at least three wells that have penetrated the fault plane in a triangular arrangement (not in a straight line).

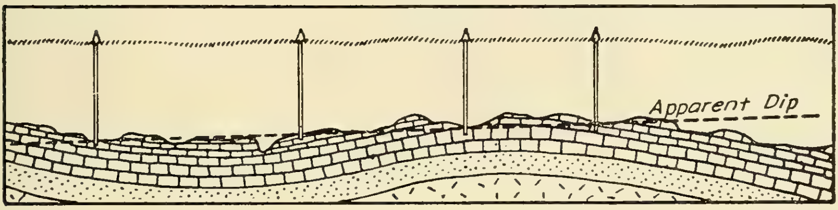


FIGURE 24-9. Effects of unconformities on interpretation of subsurface structure.

It is first necessary to determine the dip and strike of the fault plane from the three or more wells. The method is shown in the fault-plane detail of the figure cited. The procedure is exactly the same as that used in obtaining a three-point dip and strike on a bed with the plane table. In the illustration, wells numbered 1 to 5 have been plotted in their correct relative positions in a separate drawing in order better to illustrate the method. In actual practice, the determination of the dip and strike of the fault plane would be made directly on the map.

Referring again to the fault detail drawing: Wells 1, 2, and 3 penetrated the fault plane at elevations 4100, 4600, and 4300 feet respectively. These wells are joined by straight lines. The difference in elevation (on the fault plane) between 2 and 3 is 300 feet. If the line is divided into three equal parts, the difference in elevation between each of these points is 100 feet. The difference in elevation between wells 2 and 1 is 500 feet; therefore, five equal spaces are laid off along that line. Now, starting with the first mark on each side of the highest well (4600 feet), strike lines are drawn as shown in the figure. These lines are contours on the fault plane and the rate of dip of the fault plane is revealed by the spacing of the contours. This process assumes a true plane, which may not actually be correct.

When the fault-plane contours have been drawn on the map, the structural contours are carefully sketched to points where they intersect fault-plane contours of the same values. These intersections, as shown on the map, mark the boundaries of the datum gap.

Although the wells used in this illustration penetrated the fault plane within the datum gap, this condition has no bearing on the solution of the problem.

The only requirement is three elevation points in the form of a triangle on the fault plane.

In the drawing, well 5 is on the 3500-foot contour of the fault plane, and the datum elevation is 4150 feet. Therefore, the fault will be encountered 650 feet below the datum at this location.

In Figure 24-11, *A* shows an anticline cut by a high-angle reverse fault. The productive area on the upthrown block is ruled. The seven wells that drilled

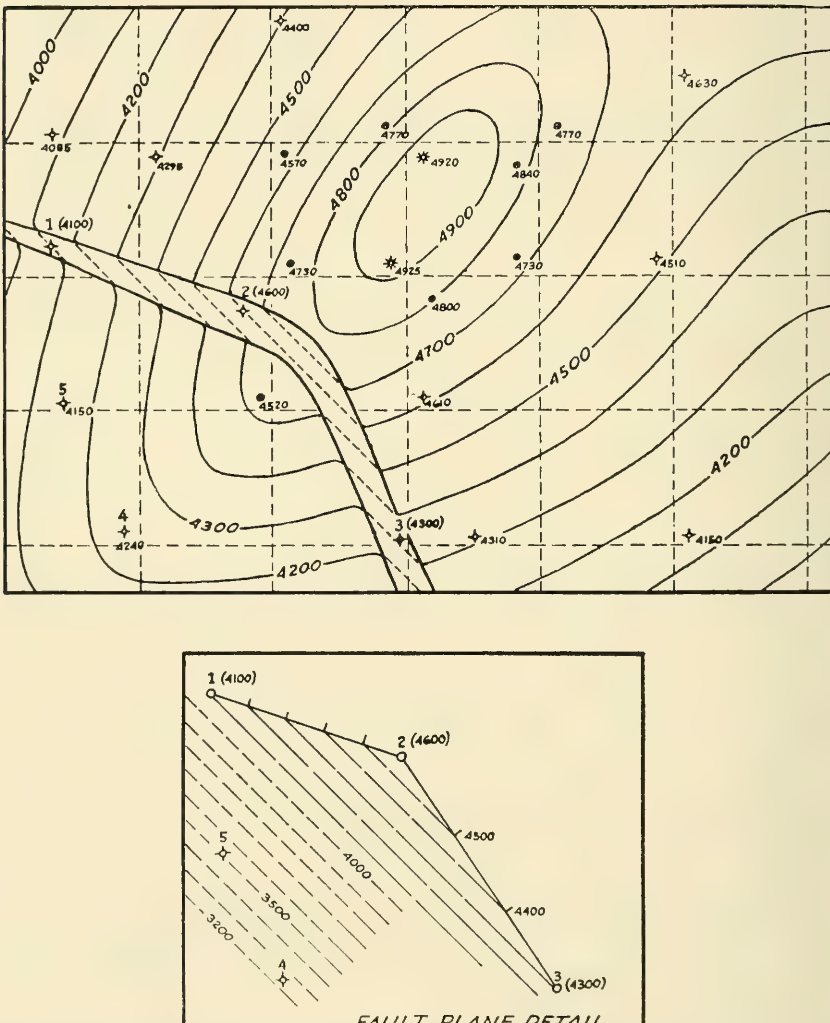


FIGURE 24-10. Structural contour map showing a datum (fault) gap and the contoured fault plane.

through the fault plane and encountered the datum beneath the fault are encircled. Three of these wells produce oil from the downthrown block. Saturated portions of the producing formation above and below the fault are shown in the cross section, *C,* of Figure 24-11. The map, *B,* in Figure 24-11 deals with the part of the datum in the downthrown block. The heavy dashed line in the central part of the area is the upper trace of the thrust sheet. The heavy dashed line in the northwest quadrant is the lower trace, and the area between these lines represents the horizontal displacement of the datum bed.

The fine dashed lines numbered 2300 to 3200 are contours on the fault plane, which is shown as a true plane, since all of the contours are straight lines. The solid-line contours are on the datum bed below the fault plane. The upper numbers at the wells are datum elevations below the fault, and the lower numbers (in parentheses) are elevations of the fault plane. As in *A* of Figure 24-11, the productive area is ruled.

The curving of the datum contours beneath the thrust sheet, northwest of the hidden syncline, suggests that some folding had taken place prior to the faulting; therefore, the possibility of accumulation of oil in the upper edge of the faulted flank beneath the fault might be anticipated, if the upturned edge of the reservoir had been adequately sealed by the fault.

The two examples of faulted structures illustrate the importance of contouring the fault "planes" cutting productive structures. As stated previously, at least three elevation points on the "plane" are required, and with only three points for control, it is necessary to contour this surface as a true plane. If a larger number of wells penetrate the fault, it may be possible to contour the irregularities and undulations of the plane.

Suggestions for Contouring

There are a few rules for contouring a group of numbers on a map:

1. Each contour line of given value must everywhere pass between those points whose numerical values are higher and lower, respectively, than that of the contour. For example, two points having elevations of 110 feet and 95 feet must not lie on the same side of the 100-foot contour.

2. No contour can cross over itself or any other contour. There are two exceptions to this rule: overturned or recumbent anticlines, and reverse faults. In practice the underside of a recumbent anticline and that part of the datum lying below a thrust sheet are ordinarily omitted on a contour map because of the confusion of lines that would result if these surfaces were contoured. Occasionally it is desirable to show the relationship by contouring the "hidden" portions with dotted or dashed lines.

3. Two or more contours may merge into a single line only where the datum is vertical or where faulting has displaced the datum along the strike by an amount equal to or exceeding the contour interval.

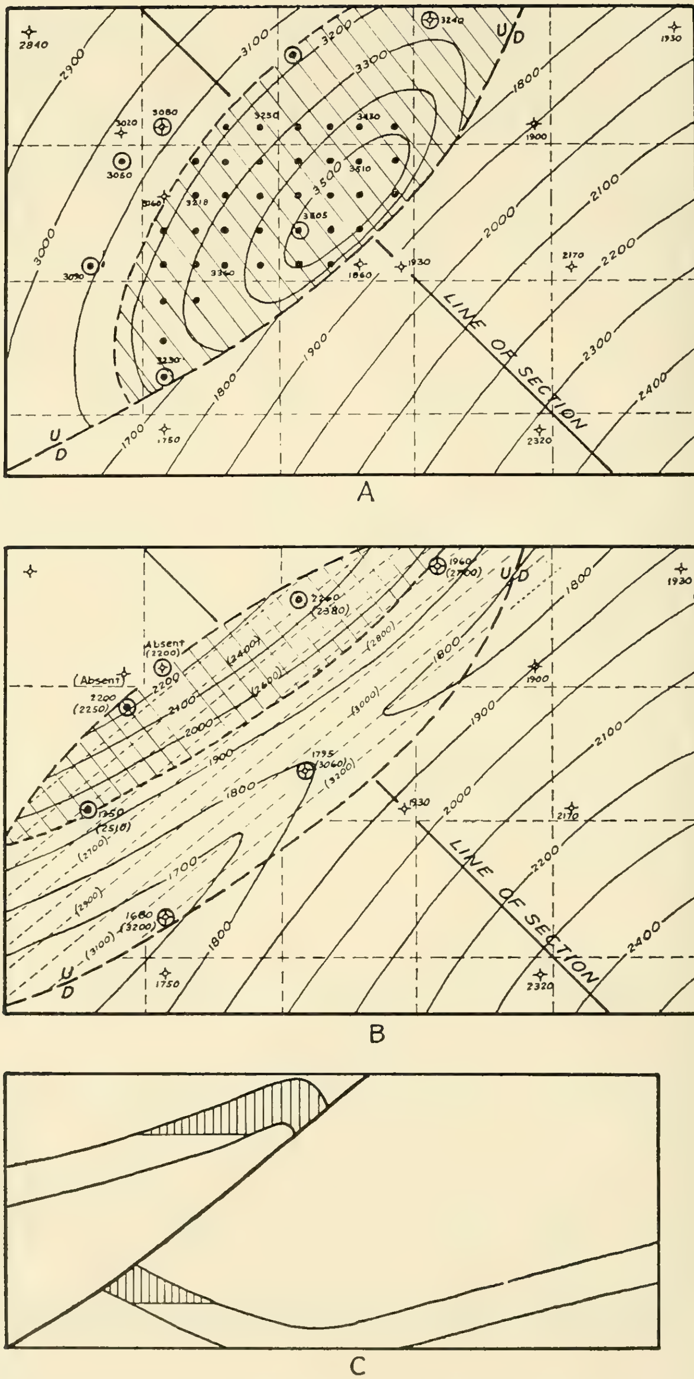


FIGURE 24-11. *A*—Structure contoured above a high-angled reverse fault. *B*—Contours on and below fault plane. *C*—Geologic cross section showing dip of fault.

A map can be contoured so that all of the technical requirements just described are fully satisfied, yet fail to convey the probable structural conditions. Such a map is shown in *A* of Figure 24-12. There are no technical errors in the contouring of this map, but it fails to give a consistent picture of structure. On

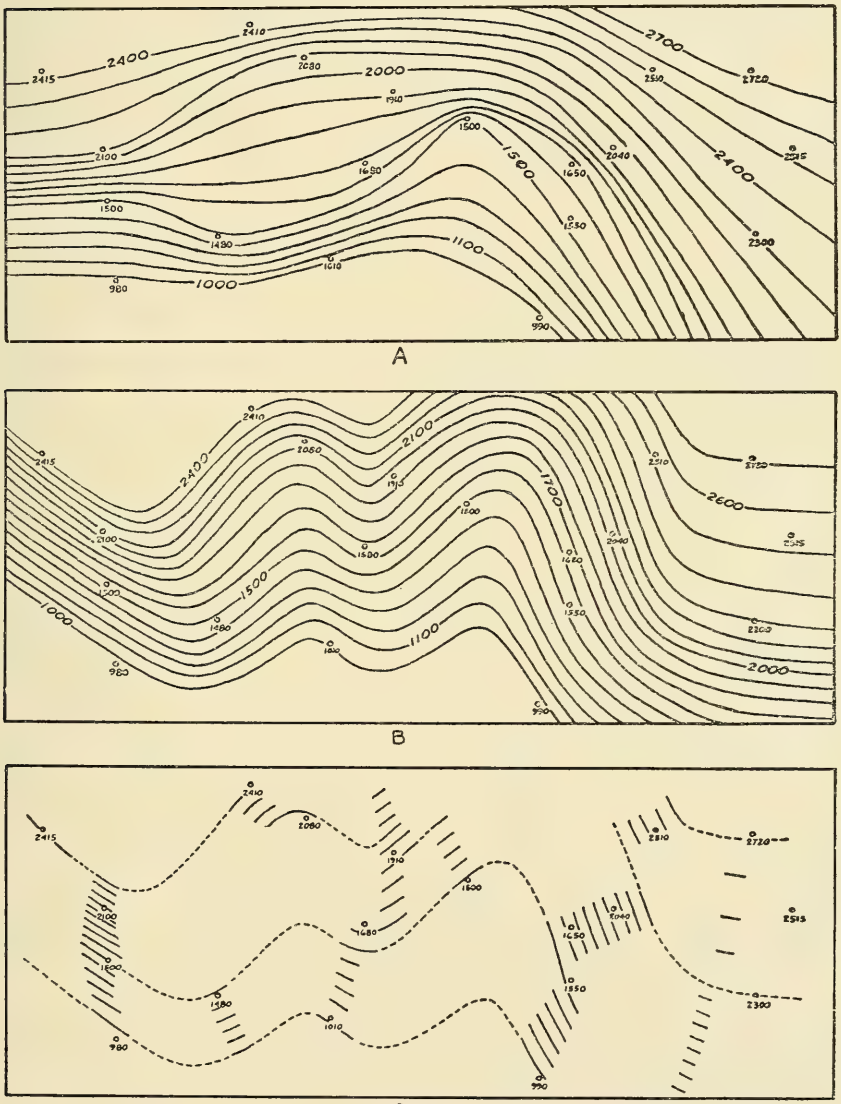


FIGURE 24-12. Contrast of careless and orderly methods of contouring the same data.

the west side of the map, the strike is east and west, but the dip varies from very low in the north to steep in the central portion and back to low in the south. In the central part of the area there is no consistency in the structural features in that contours are pinched together in some places and widely spaced at others. The east side shows a constantly changing dip and strike. Although it is quite possible for such structural conditions to exist, it is not probable.

In Figure 24-12, *B* shows the same control points contoured in a manner that reveals two plunging anticlinal noses, two synclines, and a well-defined terrace. This sheet was contoured, not to tie the widely separated control points together in the simplest manner, but rather to develop the forms of any geologic structures that might be suggested in the variations in the rate of dip or changes in strike. In other words, this map bears the unmistakable marks of geologic interpretation of the data.

A knowledge of the general character and form of structures in the region aids greatly in correctly interpreting the subsurface structure where the well control is sparse. When the character of folding is known, an attempt should be made to contour the widely scattered points so that the features shown bear out the regional trends or tendencies. Often the subsurface geologist is called upon to construct structure maps where little is known about the regional trends. However, there are usually some clues in the datum elevations themselves. A common but often erroneous assumption is that most of the higher wells are on the highest parts of local structures, and most of the lower ones are on the lowest points of the structures. When one is starting to contour the subsurface map, it is better not to be too strictly constrained by the few scattered elevations on the sheet. In some places the actual structural elevations probably exceed those of the highest wells and at others are less than those of the lowest wells. As long as the technical requirements of contouring are adhered to, the geologist has considerable license, and he should endeavor to present a consistent and feasible picture.

Figure 24-12*C* illustrates the method by which the map *B* was constructed. A cursory inspection of the datum values of the wells shows that the regional strike is roughly east and west over most of the area. A high rate of dip is shown between elevation 1500 and 2100 feet on the west side and 1650 and 2040 feet on the east. It is assumed that at these two localities the pairs of wells are aligned somewhere near the direction of full dip, and that from these wells to other nearby ones, where a much lower rate of dip is suggested, the directions are along components of the true dip. Therefore, the contours are drawn in such a way that a consistent rate of dip is maintained. If one assumes a northwesterly strike through points 2100 and 1500, the points 2415 and 980 are contoured with negligible variation in either dip or strike. A similar procedure is followed for each locality where the distribution and relative datum elevations of the wells provide the best control on the rate of the dip and the local direction of the strike.

These areas are then joined by extending certain contours with values nearest those of scattered datum points located between the detailed areas, as shown by the dashed lines in the figure. These lines form the skeleton of the map, and it is a simple matter to fill in the remaining contours.

It is sometimes possible correctly to infer the presence and magnitude of a fault by working according to the principles just outlined. In *A* of Figure 24-13 an anomalous dip is indicated on the east flank of the anticlinal nose. Both dips

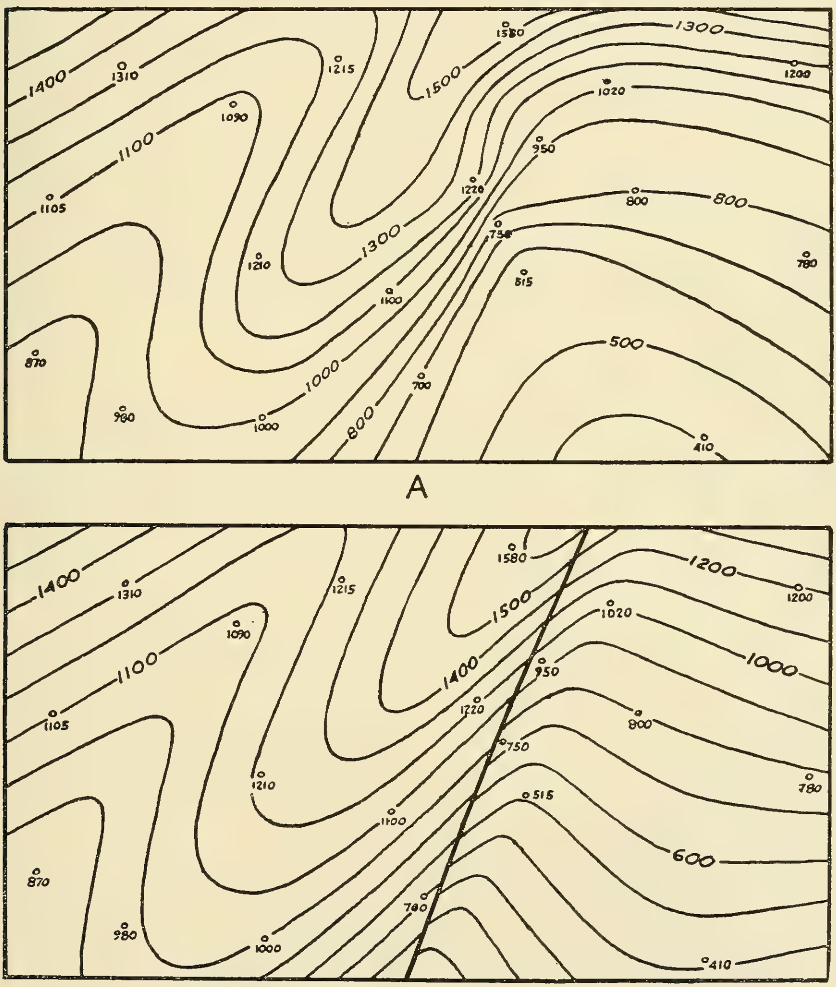


FIGURE 24-13. Examples of simple and interpretative contouring of the same data.

and strikes are erratic in the eastern one-third of the map. Now, in *B* of Figure 24-13 the same control points have been carefully contoured, particular care having been taken to maintain constant rates of dip locally and gradual changes in strike. Instead of contouring through the anomalous values 1220, 750, 950, and 515, without regard to the structural conditions thus developed, a more methodical plan was used. In this case the contouring should be developed from the east and west edges of the area toward the locality of erratic elevations, each side being treated independently of the other. It is essential that the spacing of the contours depict a consistent structural condition, which can usually be attained only by trial and error in drawing the contours. When this procedure is followed, the presence of a fault with a throw between 200 and 400 feet is clearly indicated.

The preceding examples are given to illustrate the importance of developing the subsurface structure with a few sparsely distributed control wells. In order to accomplish this result, it is necessary to think geologically—to visualize the various structural forms as if they were solid models and to contour these forms in a manner that will withstand critical geologic analysis. As mentioned earlier, it is a very elementary task to contour a sheet technically correct. The geologist must go further—his map must be technically correct and geologically feasible.

Isopach Maps

An isopach is a line of equal stratigraphic thickness, and an isopach (or isopachous) map is one which shows by means of isopachs the variations in stratigraphic thickness of a stratum, formation, or group of formations. As in the case of structural maps, isopach maps may be either surface or subsurface, depending upon the class of data used in their construction. The subsurface isopach map is based primarily upon formation thicknesses determined from well cuttings or electric logs.

Although isopachs must be drawn to agree with thicknesses plotted on the map, their spacing and the nature of thickening and thinning may be guided largely by other known facts concerning the source of sediments, their relative rates of deposition, truncation, and so forth. An isopach map drawn strictly to the numerical values and without regard to the geologic reasons for thickening and thinning of the formations is likely to present a picture difficult to reconcile with other geologic facts.

The isopach map *A* in Figure 24-14 is drawn according to thicknesses shown at the wells. No consideration is given to the reasons for the body of thicker sediments in the central part of the area or the changes in rate of thickening in the two regions where the formations are absent. The same points are contoured in *B* of Figure 24-14 with much better effect. The close spacing of the contours from zero to 200 feet on the west side of the map indicates the area

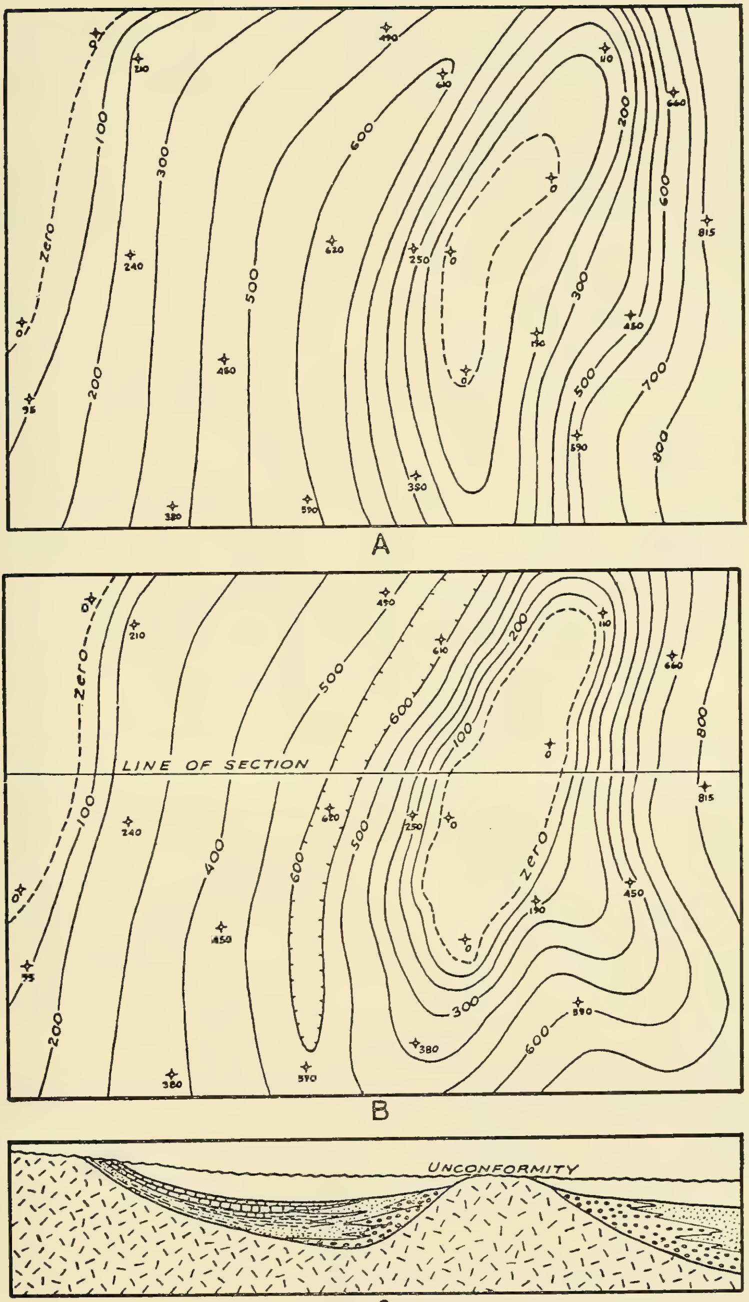


FIGURE 24-14. Two interpretations of contouring the same isopach data.

of truncation where the formations are tilted along the granite mass. The cross section shows that the limestones are of about the same thickness here as at points much farther into the basin, and there are no conglomerates that would suggest a near-shore sedimentation environment. The conclusion is that the higher rate of thinning is caused by truncation of the upturned edges of the strata, and the close spacing of the contours is, therefore, maintained parallel to the granite area.

Around the uplift on the east side of the map area, the control points show a high rate of thickening. The well samples contain large quantities of coarse arkosic sands and conglomerates, and it is assumed that the granite mass was the source of the sediments. With this knowledge at hand, the contours are drawn so that the nature of these deposits indicates the size and shape of the blank granite area within the zero line. Finer sediments in wells 190, 450, and 590 suggest a higher and less precipitous terrane; hence, the nose plunging to the southeast corner of the area.

It might be pointed out that the map *B* and section *C* clearly show that the central uplift is older than the sediments and at the time of sedimentation was higher than the granite area on the west side of the area. Conversely, the western arch is probably younger than the sediments, because the flanking rocks are similar to those in the central portion of the structural basin.

A common source of error in subsurface isopach maps is the too-great apparent stratigraphic interval caused by steeply dipping strata at the point

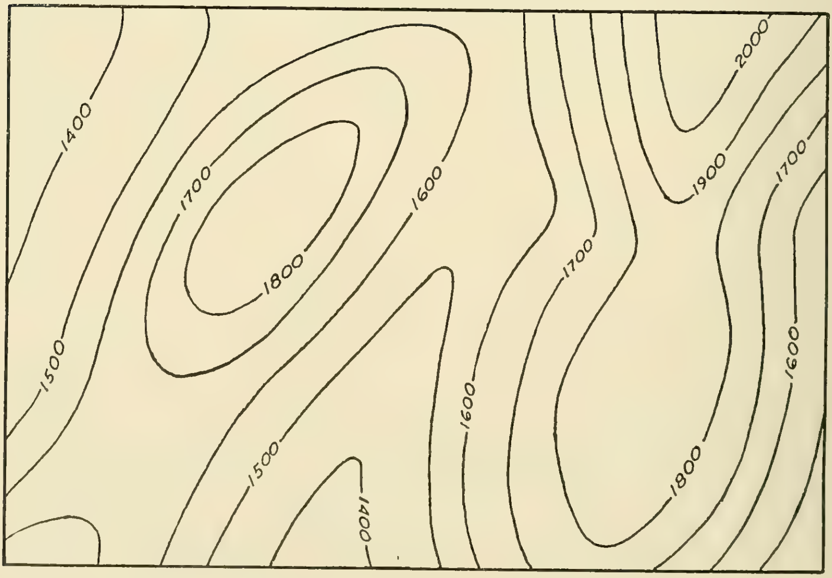


FIGURE 24-15. Subsurface structural map on top of Pennsylvanian.

where the well is drilled. Obviously, a correct interval is obtained in a straight hole only where the beds are level. Since most wells are drilled on structures, there are many opportunities for wells to penetrate formations where appreciable dips do exist; and, if the dips are quite steep, the error in interval may be large enough to affect the regional aspects of the isopach map. There is little doubt that the apparent thinning of the section on the tops of some structures is only the result of this condition. If core dips are available, the true stratigraphic thicknesses can be determined by Busk's or some similar method for obtaining stratigraphic thicknesses in inclined strata.

Although the subsurface maps representing drilled thicknesses are commonly called isopach maps, a more precise term is isochore. An isochore map is one that shows by contours the drilled thicknesses of the formations, without regard to the true stratigraphic thicknesses. The term is not ordinarily used but is mentioned here simply because it does come up occasionally in geologic literature.

Isopach maps are interesting to draw and frequently reveal intriguing and perplexing problems, but too often their many practical uses are not fully realized or employed in subsurface work. Isopach maps are generally used for the purpose of predetermining drilling depths to specific horizons in wildcat wells. They are also used as a means of locating buried structures in regions where formations habitually become thinner over the crests of structures. A third

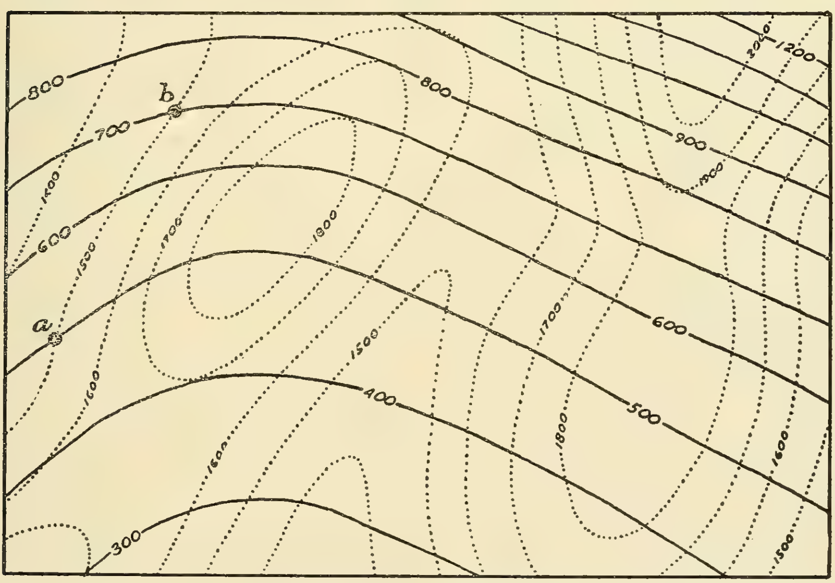


FIGURE 24-16. Isopach data of Pennsylvanian superimposed on structural map (fig. 24-15).

common use is in estimating the elevation on a datum bed below the total depth of a well that has penetrated a higher known stratigraphic horizon. But there are many other practical uses, some of which are described below.

Figure 24-15 is a subsurface structural map on the top of the Pennsylvanian. In the northwest quadrant is an anticline with more than 100 feet of closure. The southward-plunging anticline on the east side is open on the north end. These structural contours are shown as dotted lines in Figure 24-16. The thickness of the Pennsylvanian is shown by solid isopachous contours. Obviously, the 900 feet of convergence over the map area will have a profound effect on the form of the structure at the base of the Pennsylvanian or at the top of the Mississippian. The procedure for reducing the Pennsylvanian structure to the Mississippian is as follows.

Point *a* in Figure 24-16 is the intersection of the 1500-foot structure contour and the 500-foot isopach contour. At this point the top of the Mississippian is 500 feet below the Pennsylvanian datum at an elevation of 1000 feet. At point *b* the Mississippian is 700 feet below the structure datum, and the elevation is, therefore, 800 feet. All intersections are reduced to Mississippian elevations in this manner, and these values are then contoured, as shown in the Mississippian structure map in Figure 24-17. Now, if it is desired to determine the structure on the top of the Devonian, the Mississippian isopach is superimposed on the Mississippian structure, as in Figure 24-18, and the process just de-

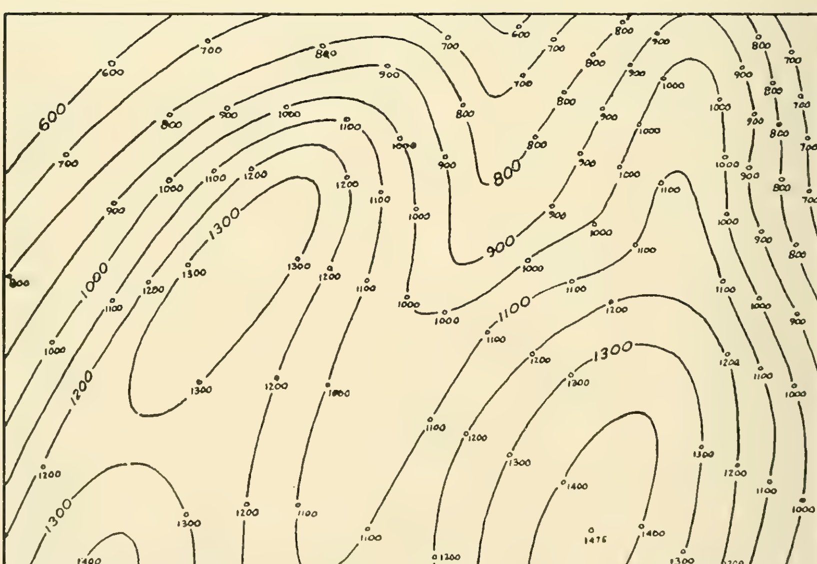


FIGURE 24-17. Subsurface structural map on top of Mississippian.

scribed is repeated. The result of this step in shown in Figure 24-19, the Devonian structure map. This figure shows the original Pennsylvanian structure map superimposed on the underlying Devonian structure map in order that the two may be compared directly. It should be pointed out that the closed Pennssylvanian structure is a northeasterly plunging nose at the Devonian horizon. The south-plunging nose on the east side of the area is a north-plunging nose on the Devonian, and if the map were extended on the south, a large closure would be evident in the Devonian.

In Figure 24-20 the combined thickness of the Pennsylvanian and Mississippian can be determined at any contour intersection simply by subtracting the lower value from the higher, if both datums are either above sea level or below sea level. Where one datum is above sea level and the other below, the contour values are *added* to obtain the thickness.

This method of reducing structural maps from higher to lower horizons should be applied wherever the rate of convergence (in feet per mile) between the structure datum and the prospective oil horizon approaches the rate of dip (in feet per mile) on the flanks of the structure.

In some regions persistent and sharply defined seismic-reflecting horizons are encountered several thousands of feet above the prospective oil-producing formations. Because of the fact that much of the wave energy is reflected here, it is sometimes impossible for the little remaining energy of the shot to reach

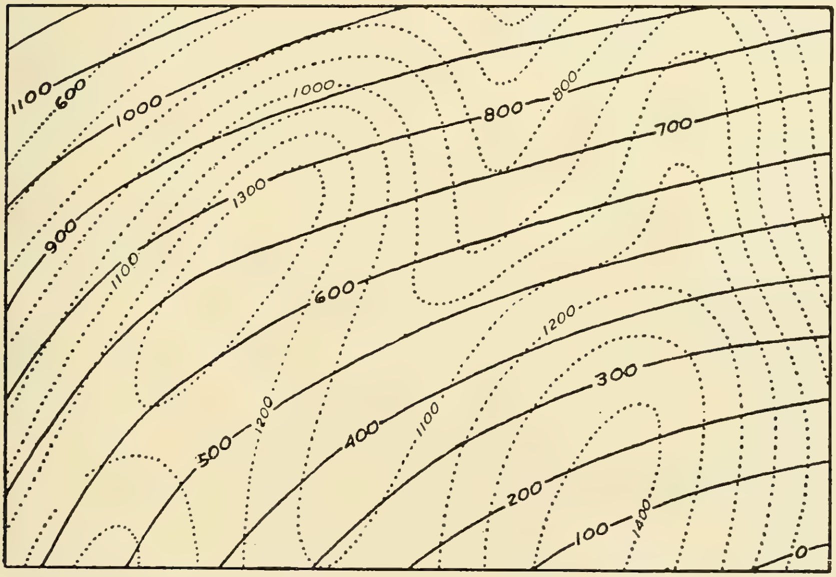


FIGURE 24-18. Isopach data of Mississippian superimposed on structural map (fig. 24-17).

the lower horizons and be reflected back to the seismometers in sufficient strength to produce usable records. Therefore, a detailed seismic structure map may be obtained on the upper horizon, but sparse data or none on the lower. Now, if a few deep wells provide the necessary convergence data, an isopach map can be constructed from the subsurface information; and, by means of this map, the seismic structure can be reduced to the prospective formation.

Isopach maps of oil reservoir rocks, together with porosity determinations from cores, make it possible to calculate the volume of oil in a structure. This method is most applicable to sandstone reservoirs where there is little cementing or other interstitial material. Conditions of porosity and thickness of saturation are normally less predictable in limestone reservoirs, and for these reasons it is difficult to make accurate volumetric determinations.

Figure 24-21*A* shows a structure contoured on the top of the producing formation. A few dry holes have been drilled on the flanks of the structure below the oil-saturated portion of the reservoir, and by means of these dry holes the oil-water contact is established at a structural elevation of 660 feet. This oil-water contact is shown by the heavy dashed line on the map and also in cross section *B* in Figure 24-21.

Since the thickness of the oil column is less than the thickness of the reservoir rock, the computation of the volume of saturated sandstone is quite simple, because the isopach map of the saturated rock is exactly the same as the

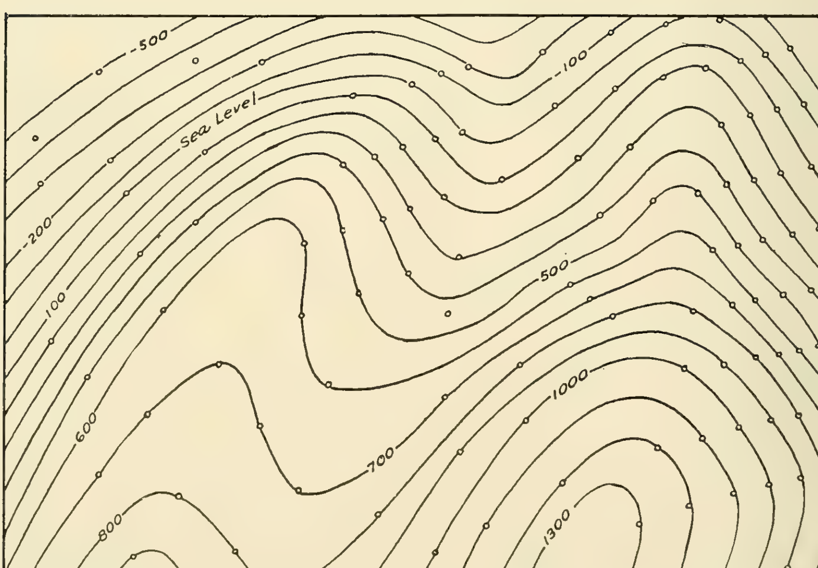


FIGURE 24-19. Subsurface structural map of top of Devonian.

structure map, with only the contour values being changed. It is clear in the cross section that the extra structural contour (oil-water line) of 660-foot elevation is the same as the zero isopach contour for the saturated zone. Likewise, the 700-foot structural contour becomes the 40-foot isopach line, the 800 becomes the 140, and so forth. The thickest part of the zone is on the top of the structure at an elevation of 1050 feet, and the thickness here is 390 feet.

The computation of volume from an isopach map is as follows:

The area contained within each contour is determined with a planimeter, or, if a planimeter is not available, the area can be subdivided into rectangles and right triangles as shown in *C* of Figure 24-21. These tracts are scaled, and areas are computed according to the scaled dimensions. The outline in the figure is the isopach zero line (660-foot structure contour). The same procedure is repeated for the next higher contour, which in this case is the 40-foot isopach. The volume of rock between these two planes is: area within zero contour + area within 40-foot contour × (40 ÷ 2). Inasmuch as this process gives the volume for only that portion between the zero and 40-foot contours, it must be repeated for the segment between the 40-foot, the 140-foot, and so on to the highest contour.

In Figure 24-22, *A* shows the structure just discussed, but, as indicated in the cross section, the reservoir rock is uniformly 200 feet thick. The procedure for determining the volume of this reservoir is considerably different from that

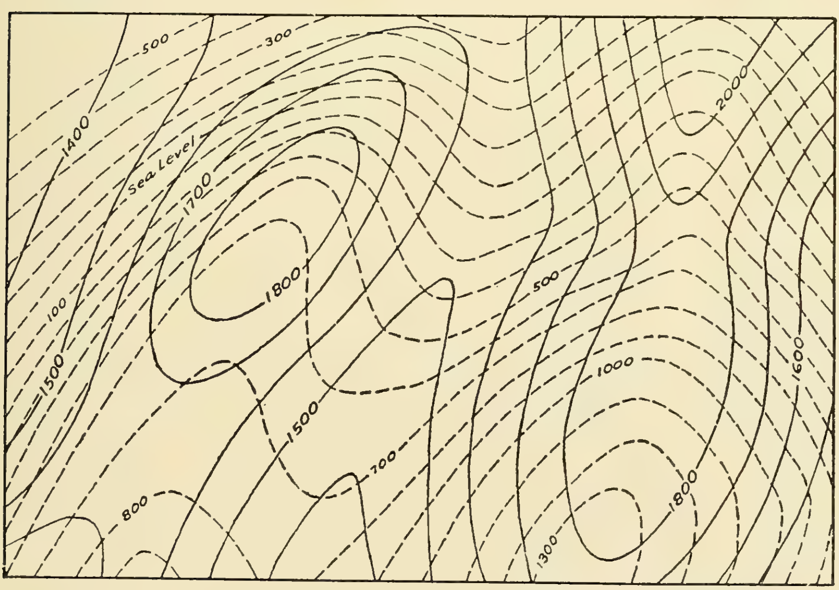


FIGURE 24-20. Devonian and Pennsylvanian structure maps combined.

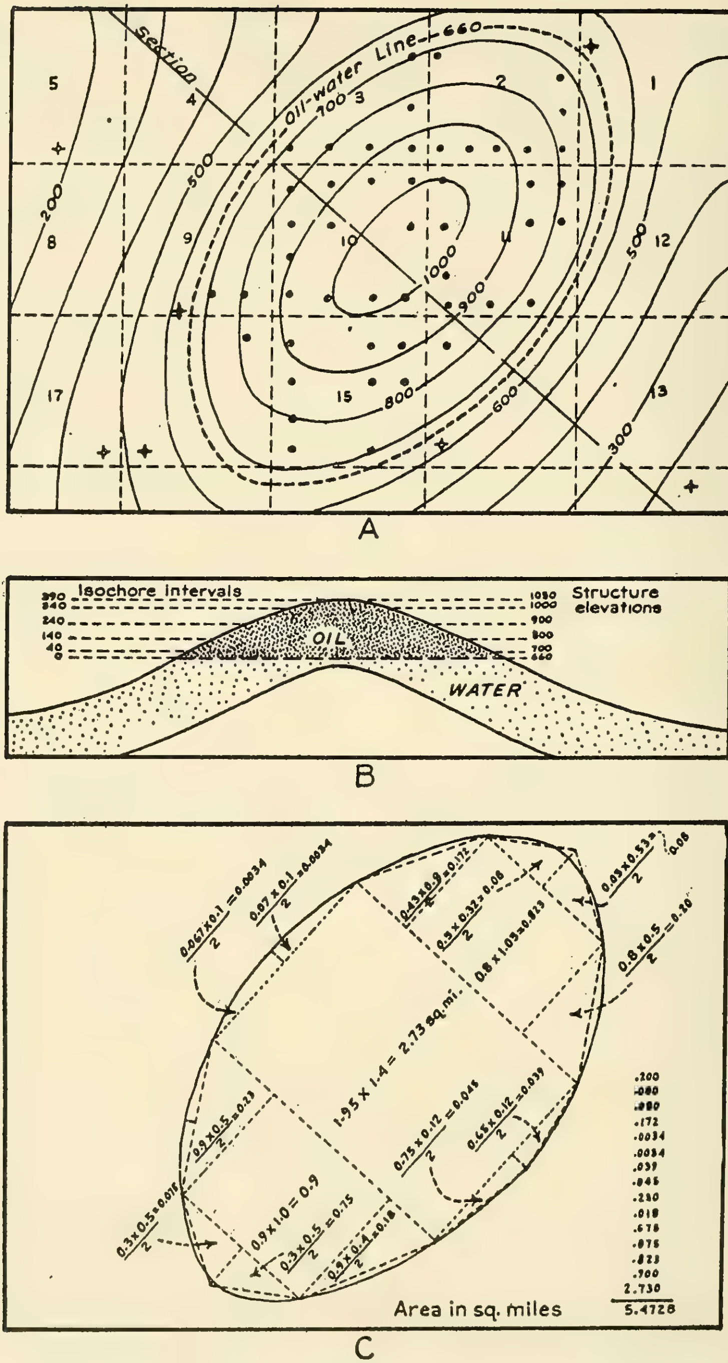


FIGURE 24-21. Method of computing oil-reservoir volume (Case I).

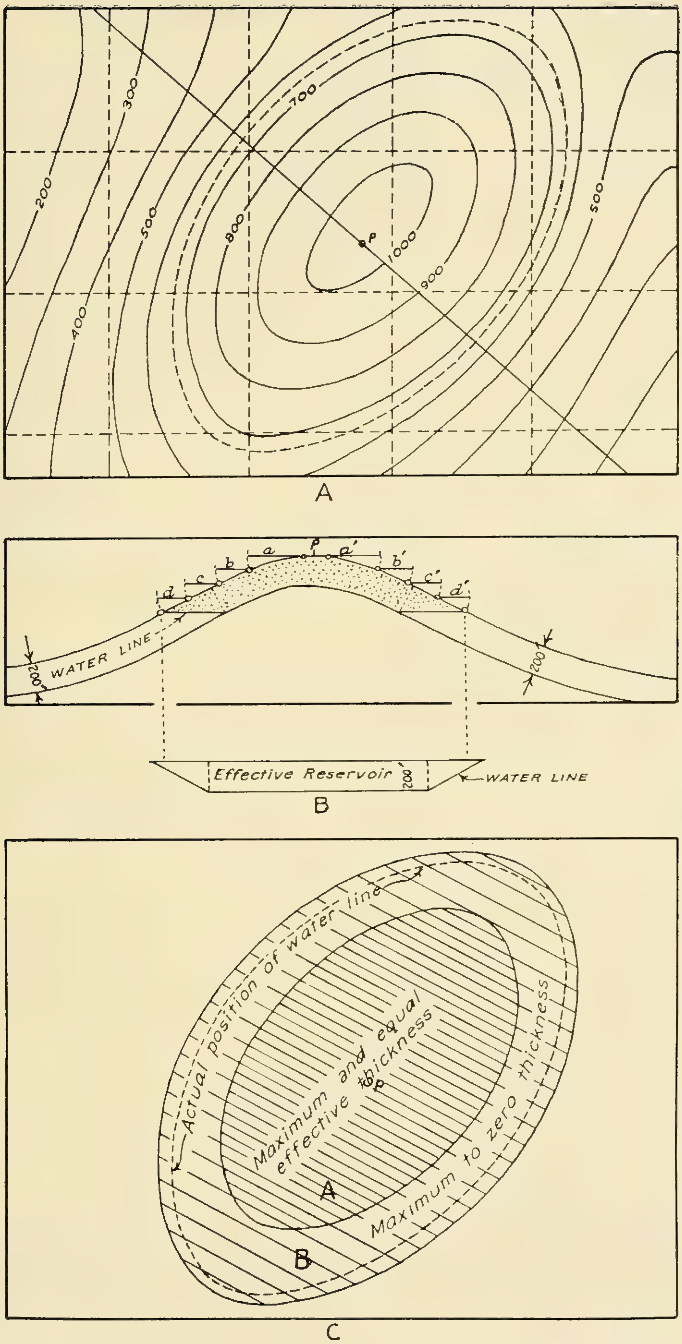


FIGURE 24-22. Method of computing oil-reservoir volume (Case II).

previously described. In this example it is assumed that the elevation of the oil-water contact plane is known and has been mapped according to the dashed line on the map. The uniform thickness of the reservoir is known from a few wells in the region that have penetrated it.

It can be seen in Figure 24-22*B* that, if the folded reservoir bed were flattened, its actual breadth would be greater than that shown on the structure map. The first step, then, in computing the volume is to determine the actual area of the reservoir, rather than the area within the oil-water line as it appears on the map. This can be done graphically by first constructing several cross sections and one or two longitudinal sections, all on a natural scale.

A series of horizontal lines is drawn across the profile. Using the intersections of these lines with the line of the profile as centers, one draws short-circle arcs upward from point to point, as shown in the figure. The sum of the distances, a to d and a' to d' is a close approximation of the surface distance over the fold. In practice, the distance over the fold may be measured directly, or the profile may be drawn on profile paper. Wherever the dip is constant, the extension can readily be computed since the distance along the sloping surface is the hypotenuse of a right triangle whose other two sides are the difference in elevation and the horizontal distance between the points (scaled on the structure map).

When a number of zero points have thus been located on the map, a new zero (oil-water) line is sketched. This is the outline of the reservoir shown in Figure 24-22*C*. The bordering band of wide ruling is that portion of the reservoir cut by the water plane. The thickness of the oil-saturated reservoir in this band increases from zero at the outer edge to 200 feet at the inner. The volume is, therefore, the area (in square feet) $\times$ 100. The closely ruled area is that part of the reservoir where the thickness is everywhere 200 feet, and the volume within that area is the area (in square feet) $\times$ 200.

The two examples will serve to illustrate the use of isopach maps in special adaptions to determine volumes. There are instances where the plane of the oil-water interface is inclined, and others where the reservoir bed varies in thickness across the structure; but it is necessary only to show these variations by isopachs to compute the volume of the reservoir. These irregular conditions require some adjustment in procedure, but not in principle.

When the volume of the reservoir rock is obtained, the volume of the contained fluid is determined by multiplying by the percentage porosity, as ascertained from laboratory tests on representative cores.

From the foregoing it is evident that the volume of any stratum, such as a coal seam or a bed of gypsum, can easily be calculated from an isopach map of that stratum. Other uses of isopach maps will be discussed in connection with paleogeologic and facies maps.

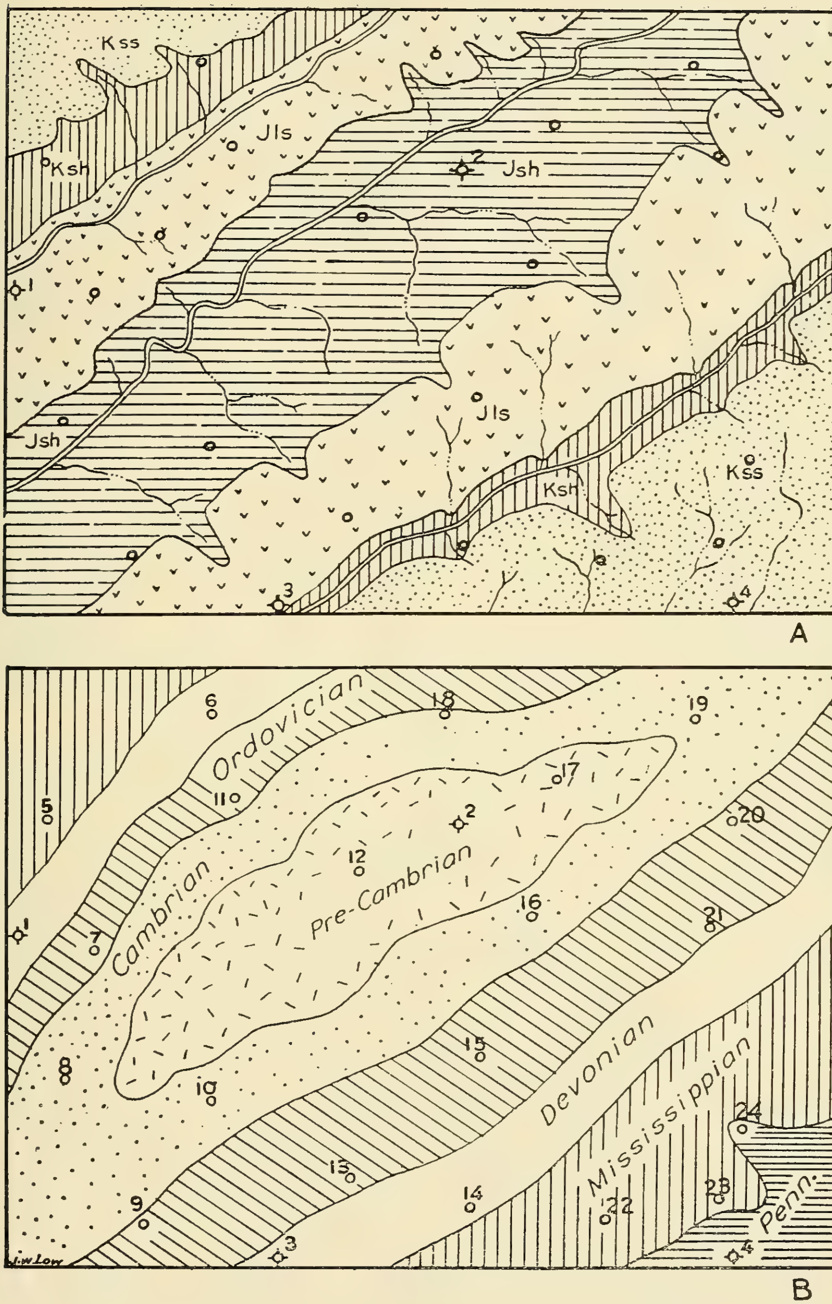


FIGURE 24-23. Paleogeologic maps. *A*—Surface areal map. *B*—pre-Jurassic areal geology.

Paleogeologic Maps

A geologic or areal geologic map is one that shows the present distribution of consolidated rocks at the surface and immediately below the soil or unconsolidated mantle. A paleogeologic map shows the distribution of formations at a surface which existed at some specific time in the geologic past. Such a surface is shown in the lower block of Figure 24-6. Figure 24-23*A* is the areal geologic map of the upper block, and *B* is the paleogeologic map of the pre-Jurassic surface in the lower block.

As might be presumed, paleogeologic maps are constructed from information supplied by wells. The four wells shown in the block diagram mentioned penetrate pre-Cambrian, Devonian, and Pennsylvanian beds beneath the pre-Jurassic unconformity. The remaining 20 wells in Figure 24-23*B* encounter rocks of different ages beneath the unconformity, and it is upon this type of information that the map is constructed.

Several factors control the relative breadth of the bands or areas that appear on the paleogeologic map. Among these are the relative thicknesses of the formations, the rates of thinning, the relative rates of dip in the different formations and the actual degree of dip, the character of the eroded surface, and the amount and character of folding subsequent to truncation. It is well to keep these conditions in mind when one is drawing a paleogeologic map, because it may be necessary to interpolate several geologic boundaries between two control points, and any one of the conditions listed above might have a pronounced effect on the map position of the boundary lines.

In the simplest case, where the formations are parallel, where the dips are constant, and where the inclination of the eroded surface is constant, the widths of the bands representing the exposed edges of the formations will be exactly proportional to the thicknesses of the formations, as shown in block *A* of Figure 24-24. In block *B*, two 100-foot members of constant thickness are separated by two others which converge markedly toward the outcrop. Because of the convergence, the lowermost member dips more strongly than the upper, and, therefore, its outcrop width is less. Block *C* shows parallel beds in a truncated monocline. Because of the difference in rate of dip, the uppermost 100-foot member is six times as wide on the outcrop as the lowermost member of the same thickness, and it is somewhat broader than a 200-foot bed immediately underlying it. Block *D* shows parallel beds with constant dips, but the surface of truncation is variable. The back edge of the block is an element of an inclined plane, and along this line the widths of outcrops are proportional to the thicknesses of the beds. Toward the front of the block, the surface becomes terracelike, resulting in the outcrop-pattern shown.

These blocks illustrate four basic conditions affecting the construction of a paleogeologic map. Any one, or all four may be operative in different portions

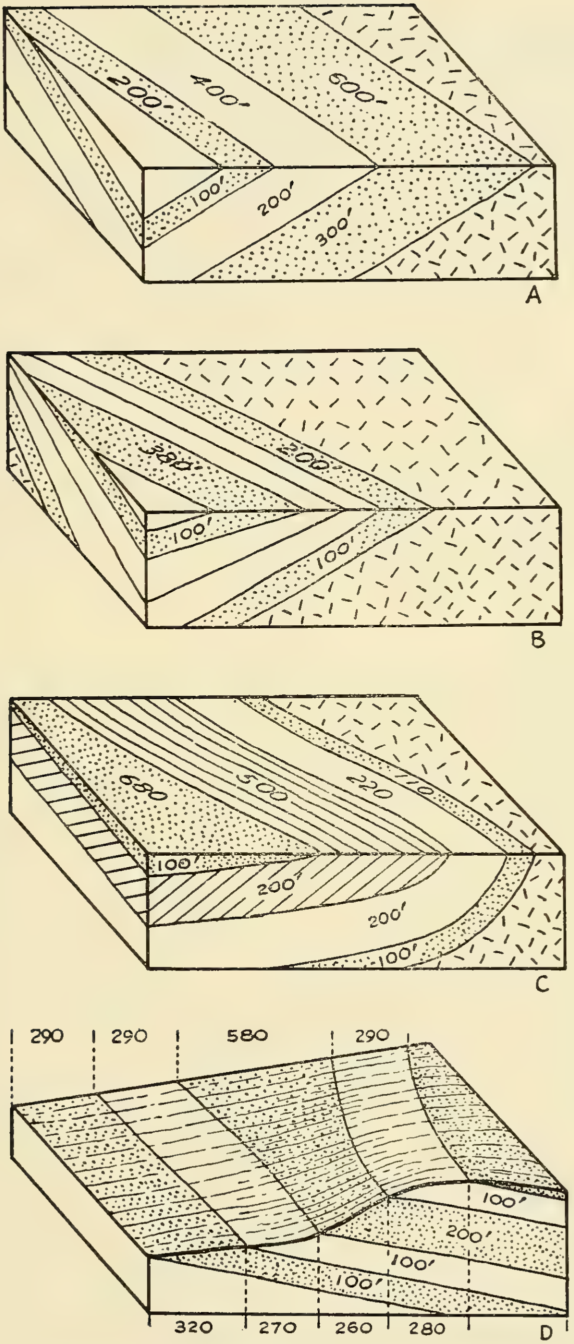


FIGURE 24-24. Block diagrams showing relationship of outcrop bands to dip and topography.

of one map area. It naturally follows that structural as well as isopach maps should be consulted in locating the geologic boundaries. For accurate results, it is necessary to contour the plane of the unconformity in order to determine the conditions shown in block *D* mentioned above.

The uses of paleogeologic maps extend into a number of fields of geologic investigation. The oil geologist applies this kind of mapping in the search for oil accumulations below unconformities. Stratigraphic traps of various types, buried zones of weathering, and outcrop trends of productive formations can be accurately mapped in areas where a considerable number of wells have been drilled. In historical geology, the paleogeologic map is not only a working tool but also an indispensable illustration. The sedimentologist utilizes the paleogeologic maps as an aid to working out knotty problems in structural histories and source areas of sediments and finally as illustrations showing by stages the progress and interruptions of sedimentation in the map area. The geologist working on regional structure can use paleogeologic maps to advantage in determining periods of folding and faulting and the chronologic development of structure. Teachers of various branches of geologic science would find their tasks diffcult were it not for maps of this general type.

Facies Maps

In stratigraphy it is axiomatic that the lithologies of any formation change in some manner from one part of a basin to another. The degree of variation and rate of change may be small or large, depending upon the physical conditions of the basin and adjacent terrane, the chemistry of the waters, the climate, and many other factors that determine the type of sediment laid down. Therefore, a single formation may be a coarse conglomerate at one locality, a sandstone or shale at another, a limestone at a third, and all three lithologies at some places. Facies changes, although perhaps not so drastic as the example given, are the usual and normal condition; and it is often of the utmost importance to the stratigrapher to determine the characters of the variations and where they occur and then to have some means of showing the change on maps.

A large number of methods have been devised by geologists to illustrate facies changes on maps—panel maps, isometric projections, certain isopach maps, and cross sections; but these methods fail in one way or another to give a complete and continuous picture where facies change rapidly and the section as a whole is highly diversified. Some methods invented for special conditions or for a special problem lack general applicability.

Most attempts to show facies changes on maps have been concerned with qualitative data, rather than quantitative. However, comparatively recently, greater effort has been directed toward lithologic analysis and lithologic mapping on a quantitative basis, and the results of this work have been gratifying. Since the scope of this book is somewhat restricted to the more practical aspects of subsurface mapping, it is necessary to omit certain methods which occasionally or locally do have practical applications but which are not generally useful in lithologic mapping. The methods described below illustrate an approach to the problems which may, in turn, stimulate further effort in evaluating complex lithologic relationships.

Lithofacies map is a comparatively new term in the geologist's vocabulary. It denotes a map that shows by one means or another the changes in lithologic facies of a formation, group, or system of rocks within a sedimentation basin. A lithofacies map may show the different facies in either a qualitative or quantitative way. Each is important in its own way. The definition of the term is broad enough to include a rather wide variety of maps dealing with the lithologic aspects of a stratigraphic section.

It is difficult, or impossible, to show by conventional maps what and where facies changes take place in a highly diversified section, such as rapidly alternating beds of shale, sandstone, limestone, and anhydrite in lenses or discontinuous beds. The relationships of each of these lithologic types to the others in the section can be shown clearly on certain types of lithofacies maps.

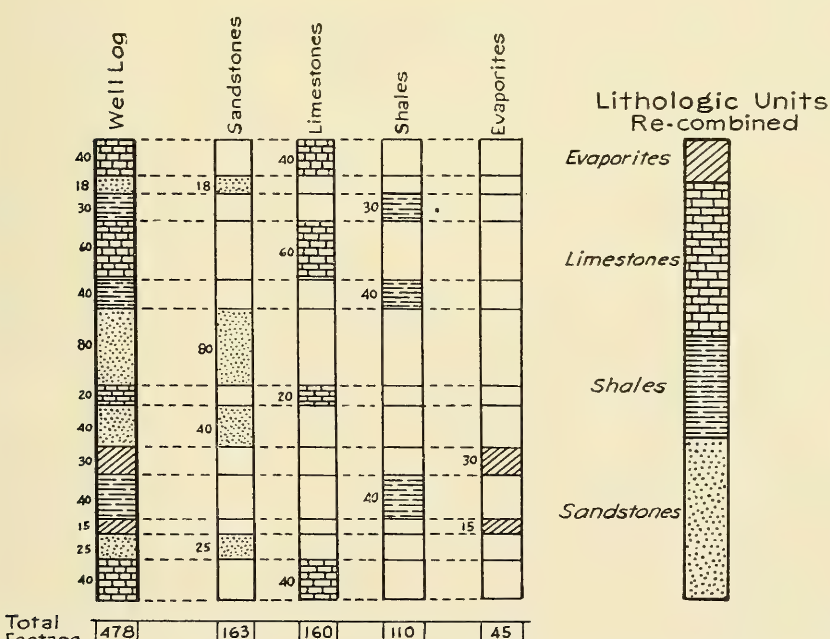


FIGURE 24-25. Lithologic breakdown of a well log into four main rock types.

Figure 24-25 shows a well log consisting of alternating limestones, shales, sandstones, and evaporites. The total thickness of this succession is 478 feet. To the right of this log are four columns, each representing a lithologic class of rocks. The first column contains only the sandstones transferred from the well —all plotted in their correct thicknesses. The total thicknesses are 163, 160, 110, and 45 feet, respectively; of course, their sum is the thickness in the original log. Now, in the column on the extreme right, these lithologic units are recombined in the simplest possible manner: i.e., all of the units of one class, regardless of the thickness of the individual members, are plotted as if they occurred as one thick bed. Thus, the 13 members of the original log are reduced to 4 in the analytic log.

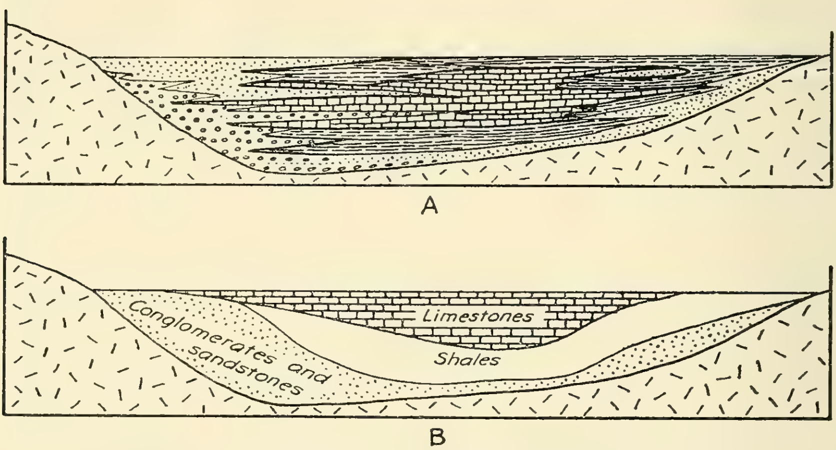


FIGURE 24-26. Simplification of a complex section according to the method shown in Figure 24-25

Figure 24-26*A* is a stratigraphic cross section showing normal facies changes from the edges toward the center of the basin. By the method described above, the complex nature of the stratigraphy is simplified (for a specific purpose) to the 3-unit section shown in *B*.

It is not necessary to replot a log in the simpler form. The thicknesses of all the individual beds of limestone, for example, are tabulated and then totaled for use on maps. A convenient form for this purpose is shown in Figure 24-27. When the lithologic breakdown of the well logs or surface sections has been made, the results are recorded in the appropriate column as aggregate thicknesses, ratios, or percentages, depending upon the mapping units to be used. Such a table provides a permanent record of all computations of lithologic proportions. The lithologic values obtained by this process may be used on maps in a great variety of ways, a few of which are discussed briefly below.

Ratio

The ratio contour map shows the ratio of the aggregate thickness of one lithologic class to that of the remaining classes that go to make up the complete section. For example, a sandstone ratio map shows the ratio of sandstones to all other rock types. Thus the ratio value of sandstones in the section shown in Figure 24-25 is $\frac{163}{160 + 110 + 45} = 0.51$. The value 0.51 is plotted on the map, and all others are computed in a like manner; then the sheet is contoured like an isopach map. A separate ratio map may be made be for each of the lithologic classes considered in the analysis.

Percentage

The percentage contour map is very similar to the ratio map, except that the number used for contouring is the percentage value of sandstones, for example, in the total thickness of the formation. Thus, in the log in Figure 24-25, this number is $\frac{163}{478} = 0.34$. Although the numerical values of the contours will be different from those on the ratio map, the general appearance of the map should be the same.

STATE: *COLORADO* FORMATION: *PERMIAN*

NAME & LOCATION	TOT. THICK.	CARBONATES		EVAPOR.		FINE CLASTICS		COARSE CLAST.		REMARKS
		LIME.	DOLO.	GYP.	SALT	SHALE	SILTST.	SAND.	CGLM.	
Amss-#1 Smith 6-21N-43W	3045	130	520	45	15	1560	365	510	—	Sample Log by John Jones
Std. Oil-#4 Black 5-7S-16W	1560	330	210	—	—	460	310	200	—	Drillers Log

FIGURE 24-27. Lithofacies-data sheet.

Isolith

The term isolith was first applied to the imaginary surface separating two adjacent but differing lithofacies. However, the term is now commonly used in an entirely different sense. Perhaps it is unfortunate that this situation has come about, but inasmuch as the trend is strongly developed toward the newer usage, the following discussions are based on these definitions:

An isolith is a line denoting the aggregate thickness of beds of only one lithology in a stratigraphic succession composed of one or more lithologies. Where only one lithology is present, an isolith and an isopach of the same stratigraphic interval are identical. Thus, a sandstone isolith in a series of sandstones, shales, and limestones is a line of equal thickness (isopach) of only the sandstone portion of the section.

By this definition, an isolith map is a contour map depicting the thicknesses of an exclusive lithology over the map area. Basically, it is an isopach map of one lithology. In a section composed of sandstones and shales, two isolith maps are required to show the total thickness distribution, whereas only one

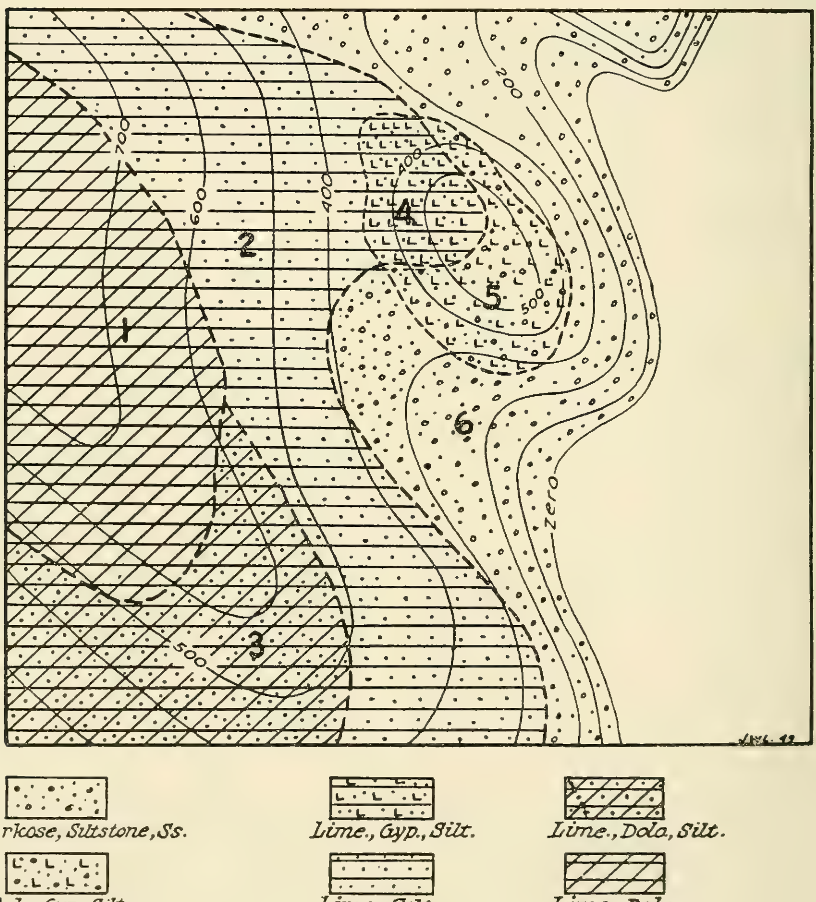


FIGURE 24-28. Combination isopach and lithofacies map.

isopach map is needed. Obviously, the sum of all the thicknesses shown on a complete set of isolith maps of a given stratigraphic interval equals the isopach map of the same interval.

Isofacies

A single lithologic facies may include several rock types. For example, one facies of a formation may consist of alternating shales and sandstones, whereas another facies of the same formation may be made up of shales, limestones, and evaporites. Since the ratio of one type of sediment to another varies within a given facies, some difficulty may develop in attempting to map such a facies by the ratio or percentage method. The complex facies may comprise only a small portion of the formation, in which instance the remaining beds would

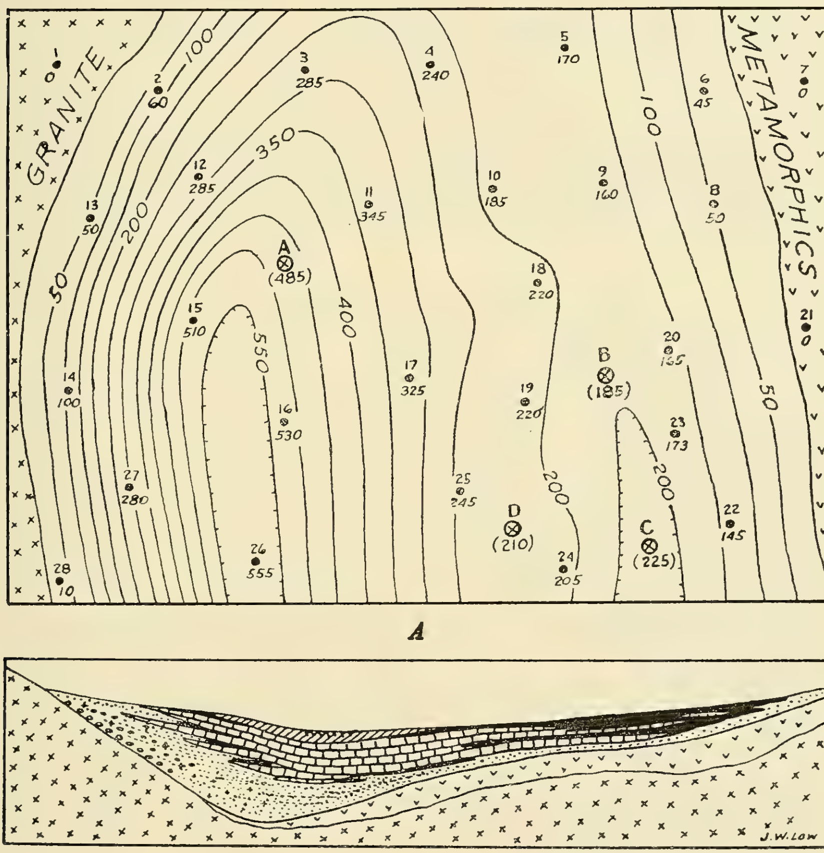


FIGURE 24-29. *A*—Isopach map of a sedimentation basin. *B*—Cross section showing complex relationships of formations.

tend to mask the effects on the percentage maps. A type of map called an isofacies map is designed to show the change in lithologic characters within a facies. The method is simple and is essentially a special adaptation of those described above. It consists in first delimiting the area and stratigraphic interval of the facies. Now, this portion of the formation can be treated as if it alone were a formation, and the required isopach or isolith maps are constructed accordingly.

A form of generalized isofacies map is shown in Figure 24-28. The contours show the total thickness of the formation, and the areas shown by different patterns within the heavy dashed lines are the various facies of the formation. These facies are as follows:

Area 1—Limestones and dolomites.
Area 2—Limestones, siltstones, and sandstones, interbedded.
Area 3—Limestones, dolomites, sandstones, and siltstones.
Area 4—Gypsum, limestones, and sandstones.
Area 5—Gypsum, arkosic sandstones, and siltstones.
Area 6—Arkoses, sandstones, and siltstones.

Figures 24-29 to 24-33, inclusive, are a series of isolith maps of a portion of a sedimentary basin. Figure 24-29 is an isopach map of the total thickness of the formation, and the cross section shows the stratigraphic relationships of conglomerates, sandstones, shales, limestones, and evaporites. This type of

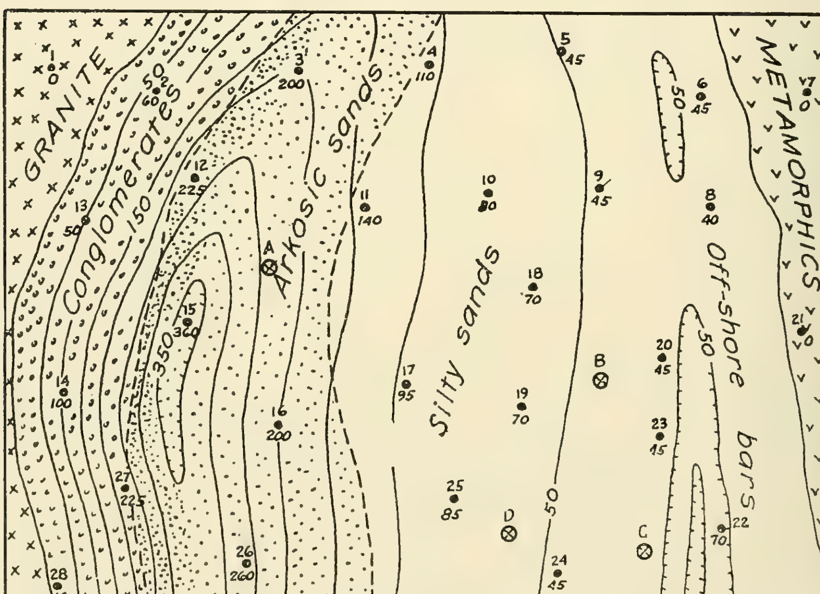


FIGURE 24-30. Sandstone isolith map of basin shown in Figure 24-29.

section is somewhat too complex to analyze lithologically on one lithofacies map by percentages or ratios. For this reason an isolith map is made for each of the principal lithologic classes: coarse clastics, fine clastics, precipitates, and evaporites. The control points used in contouring are wells whose logs have been broken down according to these lithologic classes and tabluated on the form shown in Figure 24-27.

Figure 24-30 is the isolith map of coarse clastic rocks: i.e., sandstones arkoses, and conglomerates. The thicknesses shown represent the aggregate thickness of all rocks falling in this classification, regardless of the thickness of the individual beds in which they occur. Thus, of two control points, each indicating a thickness of 100 feet, one might be made up of two 50-foot members, the other of five 20-foot beds. They have the same values on the isolith map.

The sandstone isolith map shows not only the aggregate thicknesses of the coarse clastics, but also the areas where certain kinds of sandstones predominate. The shale isolith shows the aggregate thicknesses of the shales and a further differentiation on the basis of color. Likewise, the limestone and evaporite maps indicate areas of different types. There are many other ways of differentiating within each of the lithologic groups; and, depending on local conditions, it may be advantageous to set up other main classes. These examples are given to indicate how lithologic facies may be drawn on maps in both a qualitative and quantitative manner.

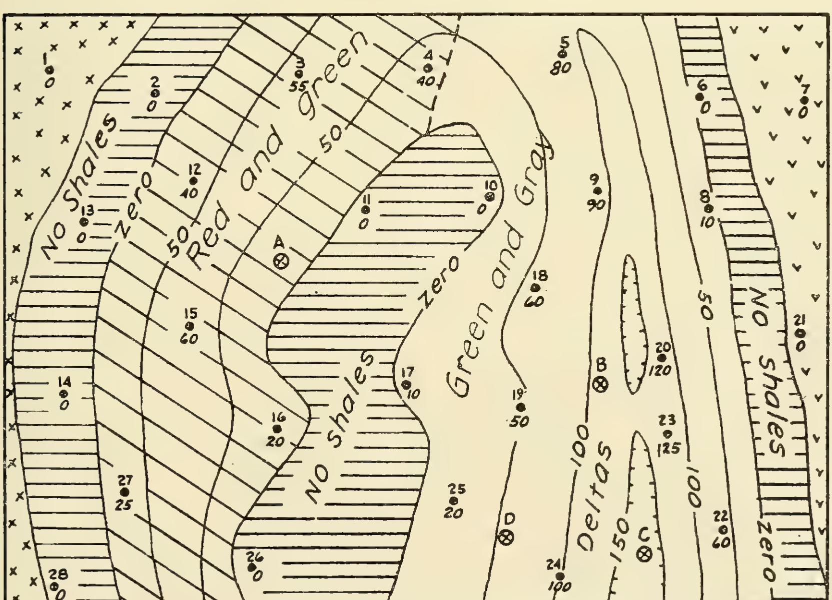


Figure 24-31. Shale isolith map.

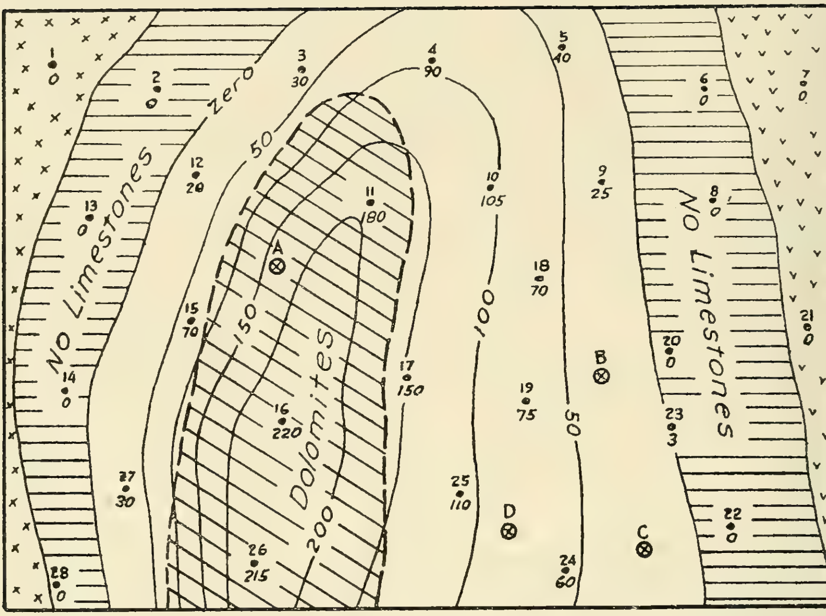


Figure 24-32. Limestone isolith map.

It has been necessary here to differentiate areas by contrasting patterns in black. This can be done much more effectively by colors. The best practice is to represent the variations within a given lithologic class by colors restricted to a definite range of hue and tone; for example, the subdivisions of limestones on a limestone isolith map should be shown by various shades of one or two basic colors chosen to represent the carbonate group; on the sandstone isolith, by shades of the basic colors selected to represent coarse clastic rocks. This procedure obviously must be varied when the facies separation is made on the basis of rock color. The only logical map presentation in this instance is to show the rock color facies by a similar color on the map; e.g., red rocks with red colors and gray with gray colors.

The chart in Figure 24-34 will serve as a guide for coloring lithofacies maps. When colors are used to represent lithologies, it is possible to show gradations from one facies into another by alternate bands of color; for example, where a sandstone facies grades laterally into a limestone facies, the area of gradation would be shown by alternate bands of blue and yellow or brown. If the proportions of sandstone to limestone are two to one, respectively, then the yellow bands should be twice as wide as the blue. This plan can be extended to include several color bands.

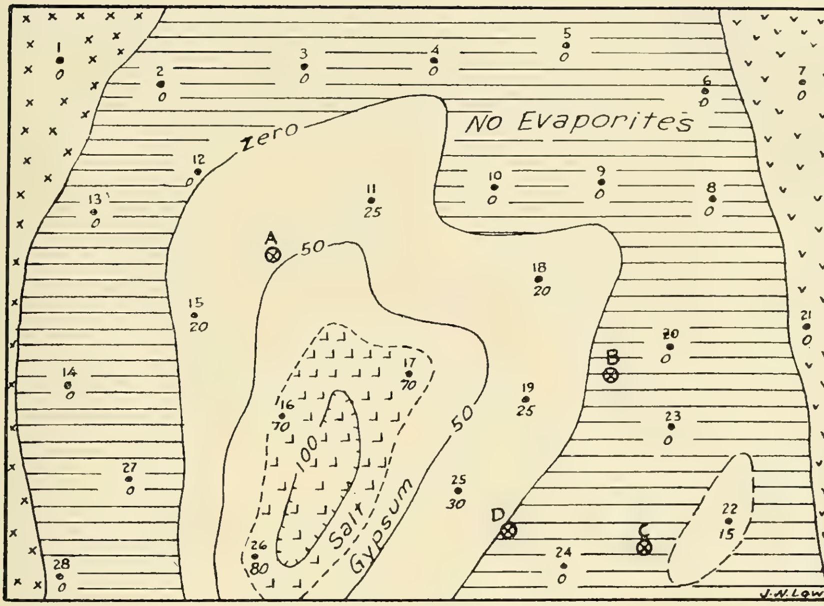


FIGURE 24-33. Evaporite isolith map.

Figure 24-35 is a lithofacies map drawn in black and white, with certain patterns representing colors, which, in turn, represent the different rock types. For very simple drawings like these, the patterns are satisfactory; but, where many lithologies are involved, the inevitable similarities of patterns in black and white make the map difficult to read.

Lithofacies maps of various kinds are almost indispensable in stratigraphic investigations in regions where the lithologic character of formations change radically from one locality to the other. Isolithic contour maps, used in conjunction with maps showing mineralogic compositions of the sediments, provide one of the best means of accurately locating with only a few points of control the source areas of clastic sediments, the areal extent of marine, continental, or fluviatile environments, and many other features vital to a thorough understanding of sedimentation processes.

In regions where contemporaneous strata are predominantly carbonates at one locality, shales and siltstone at another, and sandstones and conglomerates at a third, an ordinary isopach map can provide only a small part of the information needed by the stratigrapher. On the other hand, isolithic maps permit each of these rock groups to be appraised separately and without the distracting effect of having to deal simultaneously with the remaining rock groups of the complete section. Obviously, the shorter the time range and the thinner the

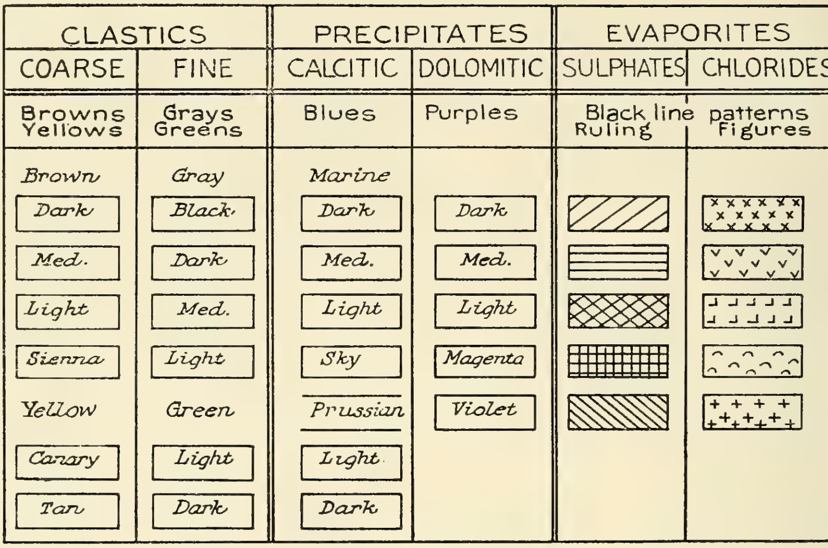


FIGURE 24-34. Guide for coloring lithofacies maps.

stratigraphic interval studied, the more precise the results will be. But the different kinds of facies maps are also an excellent method for studying thick series of strata which, because of monotonous repetition of similar units, cannot be subdivided into thinner mappable units.

An isolithic map, as explained earlier, shows the aggregate thicknesses of beds in a specific lithologic class, but it does not necessarily differentiate the rocks within this class on a mineralogic, chemical, or physical basis. There are several ways in which this differentiation may be shown. One simple method is to show such a breakdown by percentage contours superimposed on the contoured isolithic map. Thus, on a sandstone isolith map the percentage of arkosic, silty, or carbonaceous sands or maximum grain sizes may be shown by color bands or a second set of contours. The thicknesses of rocks alone, sometimes fail to reveal the sources of the sediments or the conditions under which they were deposited; but this information, together with that suggested above, often clarifies an otherwise cloudy picture.

A word of caution should be given in the interpretation of isolithic maps. Apparent discrepancies in the locations of apparent highs and lows within large basins are bound to occur if the predominance of one lithologic class in one locality is replaced by that of another class at other localities. For example, on a coarse clastics isolithic map, the thickest deposits are likely to lie close to the source materials near one edge of the basin and will thin out toward the central part of the basin. Conversely, the limestones and evaporites may reach their maximum development farther toward the center. Therefore, coincidence of the thin and thick areas on the two maps should not be expected. This is one of the reasons that the isolithic maps are of such importance in the study of stratigraphy. From the foregoing it is clear that a set of isolithic maps with their opposing thin and thick sections will tend to cancel one another out in an overall isopach map of the same stratigraphic interval. In other words, the isopach map may be generally featureless, whereas the series of isolithic maps reveals much of the stratigraphic information sought.

W. C. Krumbein, of Northwestern University, describes the ratio method of lithofacies mapping in the *American Association of Petroleum Geologists Bulletin* No. 10, Vol. 32, 1948. As mentioned earlier, the ratio method of mapping lithofacies is essentially the same as the percentage method. However, the relative spacing of contours may vary greatly.

Figure 24-36 is an isopach map of a group of rocks consisting of sandstones, shales, limestones, and anhydrites. This map is used as a guide for drawing the lithofacies map of Figure 24-37. Table 24-I is a summary of the control points, showing the total thicknesses, thicknesses of clastic and non-clastic rocks, the clastic percentages, and clastic ratios. The values in the last two columns are obtained from the following formulas:

$$\text{Clastic ratio} = \frac{\text{sandstones} + \text{shales}}{\text{limestones} + \text{anhydrites}}$$

$$\text{Clastic percentage} = \frac{\text{sandstones} + \text{shales}}{\text{sandstones} + \text{shales} + \text{limestones} + \text{anhydrites}}$$

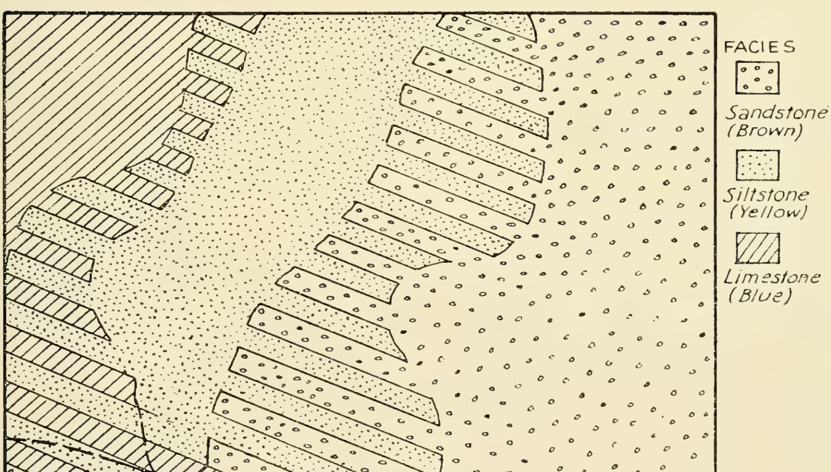


FIGURE 24-35. Lithofacies map.

In Figure 24-37 the clastic percentages are shown by solid contours. The clastic ratios are shown by dashed lines, and ratio intervals are indicated by shading. The 50-percent contour is also the ratio 1.0 contour.

In general the two methods are very similar, the principal difference being that the percentage map is contoured on a regular contour interval of 10 percent,

TABLE 24-I

Well No.		Thicknesses		Clastic & non-clastic	
	Total	Clastics	Non-clastic	%	ratio
1	140	130	10	91	13.0
2	190	160	30	84	5.3
3	220	160	60	76	2.4
4	270	170	100	63	1.7
5	270	160	110	59	1.4
6	340	150	190	44	0.8
7	360	180	180	50	0.8
8	370	180	190	49	0.9
9	380	170	210	45	0.8
10	450	160	390	35	0.4
11	520	180	340	37	0.5
12	530	190	340	36	0.6
13	530	200	330	38	0.6
14	210	160	50	76	3.2

whereas the intervals of clastic ratios are 0.5, 1.0, 5.0, and 10.0. If the ratio-contour interval were constant arithmetically, the contour *spacing* would decrease at an exceedingly high rate toward the higher ratios. Therefore, as Krumbein points out, the contour interval should be determined by a logarithmic or geometric means. For this reason the percentage method of contouring the relationships between clastic and non-clastic constituents is simpler, more direct, and generally more practicable. It should be stated in fairness to the ratio method, however, that it tends to emphasize areas where the clastic constituents form a substantial part of the section; hence it is a good method for some types of very generalized, broad regional work. Conversely, where contour points are numerous, and the data reliable, the percentage maps are better.

Alternation Frequency (Rate)

Lithofacies maps generally indicate the relative or absolute quantities of the principal lithologies in a section, but they do not reveal the manner in which these lithologies occur; therefore, a section consisting of alternating thin lithologic units is not distinguished from one composed of a few thick units. This situation is at least partially rectified by employing an *alternation frequency* or *alternation rate* map, which may be constructed according to the following procedure.

The stratigraphic interval to be studied is determined by correlating logs or surface sections over the map area. Next, the number of alternating lithologic units in the section is determined for each well and these numbers are plotted on a base map at the correct locations and contoured. Now when this sheet is registered over an isopach map of the same stratigraphic interval, the *average* thickness of the lithologic units can easily be determined at any location. A modification and more practical application of the alternation map is outlined below.

The alternation *rate* or *frequency* is based on some predetermined stratigraphic interval, as, for instance, 100, 500, or 1000 feet. The number plotted on the map would then be the number of changes in lithology per 100, 500, or 1000 feet, as the case might be. The advantage in this method is that the rate of

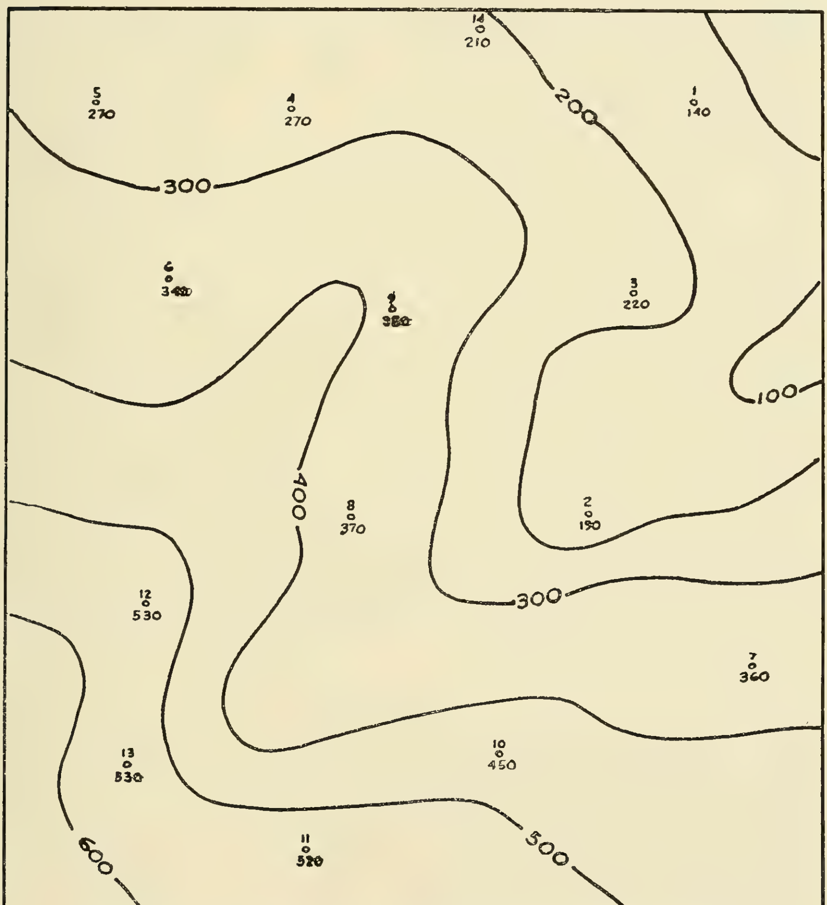


FIGURE 24-36. Isopach map used as a base for clastic-ratio map.

alternation is independent of the thickness of any one section. If a well does not penetrate the entire interval, an alternation rate can nevertheless be determined for the portion of the section drilled. Table 24-II illustrates the application of this principle.

It is evident that the *rate* of alternation is independent of the thickness of the interval; for example, in well 1 the rate is 16 changes in lithology per 500 feet of section. If the section were 1000 feet thick, there would be 32 alternations; but the rate would remain the same, as would the value plotted on the map for contouring.

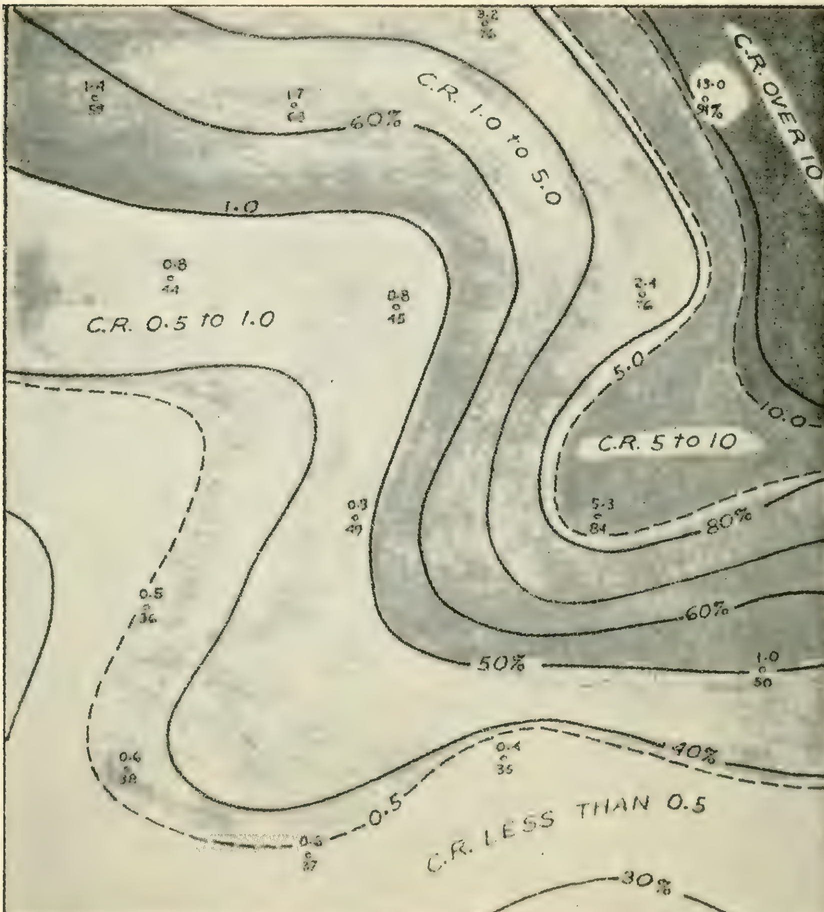


FIGURE 24-37. Map showing clastic percentages in solid contours and clastic ratios in dashed contours. Clastic ratio of 1.0 = 50 percent.

TABLE 24-II

Well	Total thickness	Actual number of alternations	Reference interval	Computation	Alternation rate
1	800	25	500	$\frac{500}{800} \times 25 =$	16
2	720	32	500	$\frac{500}{720} \times 32 =$	22
3	460	32	500	$\frac{500}{460} \times 32 =$	35

It should be emphasized that the alternation rate map, though very useful, can be quite misleading with respect to actual stratigraphic conditions. In a succession of sandstones and shales where the average thickness of the sandstones is 10 feet and the shales, 20 feet, the average of both lithologies is 15 feet. However, if the alternation rate map is used in combination with an isopach map and a sandstone percentage map, a fair representation of actual relationships is obtained.

In Figure 24-38, *A*, *B*, and *C*, is a series of maps consisting of an isopach of the total stratigraphic interval, composed of sandstones and shales, a sandstone percentage map, and an alternation map based on a 100-foot unit interval.

Figure 24-39 shows the three maps referred to registered one over the other The alternation rates are shown by dashed contours, and shading is used to emphasize the region of the highest rate of alternation. At location *a* the total thickness (from the isopach) is 500 feet; sandstones comprise 40 percent of the section (from the percentage map); and the rate of alternation is 10 per 100 feet of interval. From these data it is a simple matter to determine the aggregate thickness of sandstones (or shales), which in this instance is 200 feet, and the average thickness of the sandstone beds, which is 10 feet. At location *b* the thickness of the stratigraphic interval is 700 feet, 20 percent of which is sandstone. The alternation rate is about 5 per 100 feet; therefore, there are 35 beds of sandstone and shale together. The average thickness of the sandstones is about 8 feet, and the average thickness of the shale units is about 33 feet.

Uses of Lithofacies Maps

Much of the preceding discussion is devoted to lithofacies maps, how they may be constructed, and what they represent. In most instances the lithofacies map, regardless of the type, is only one phase of regional geologic investigation and analysis. These maps do not depict a complete geologic story, but, rather, present complex stratigraphic data in a simplified form so that broad concepts can be developed. All the various lithofacies maps discussed reveal only the *averages* of geologic phenomena. None is precisely specific where

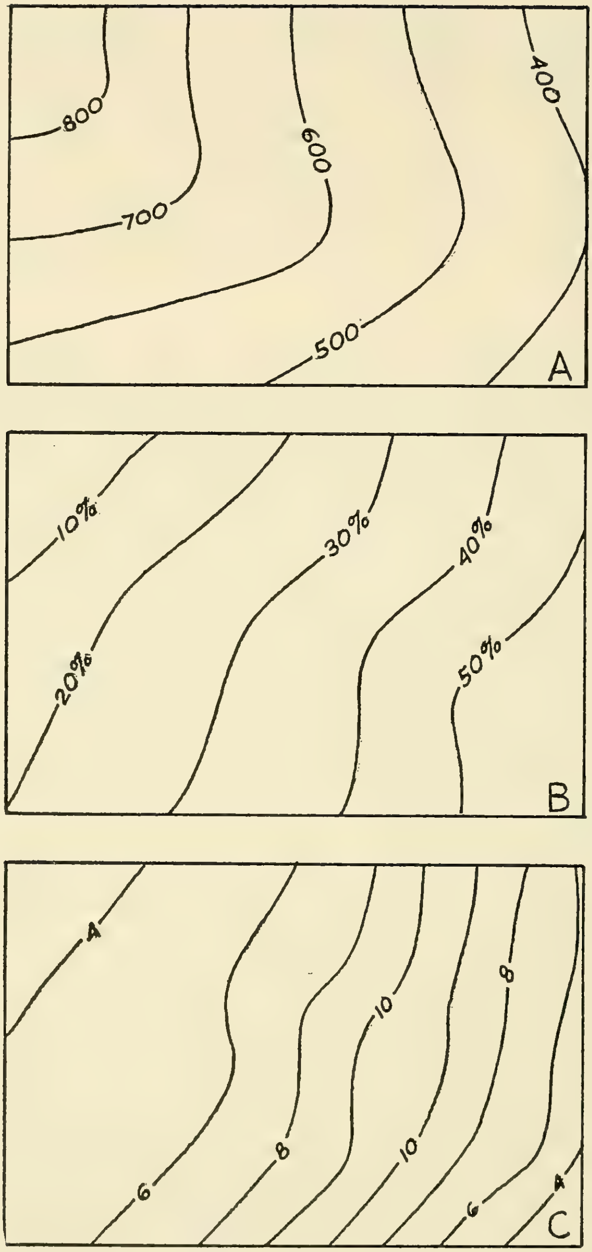


FIGURE 24-38. *A*—Isopach map. *B*—Percentage map. *C*—Alternation map.

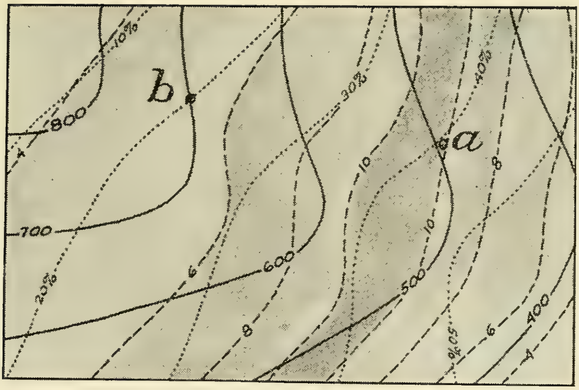


FIGURE 24-39. Maps *A*, *B*, and *C* of Figure 24-39 combined.

the stratigraphic section is complex. Maps contoured on the basis of percentages, ratios, or aggregate thicknesses of lithic classes do not take into account the *manner* in which the individual units occur. As stated before, ten 5-foot units have the same contouring value as one 50-foot unit. There are means of further classifying a lithofacies map so that it yields the practical information desired. The following example will illustrate a direct practical application of a lithofacies map.

The problem is to determine the amount of effective reservoir sand and its relative worth over a broad area. It is assumed here that individual sands less than 25 feet in thickness, even though several such units occur in the section, are not worth exploitation. Since these thin units might coalesce to form more attractive reservoirs, locally, they must be given some consideration.

The first step is to construct a sandstone isolith map. In tabulating thicknesses from the logs, extremely thin beds are omitted. Sandstones containing a great deal of clay or silt may also be ignored, particularly if it is known that such characteristics are persistent over the region. Figure 24-40 shows an sandstone isolith prepared in this way. This isolith map includes sandstones as thin as 5 feet; but since the objective is to classify sands on the basis of a 25-foot thickness, the next step is as follows: First, the percentage is computed by total thickness of all sands that occur in beds 25 feet or greater in thickness. Thus, if the total thickness of sandstones in a well is 150 feet, occuring in beds of thicknesses 30, 25, 40, 35, 10, and 5 feet, the effective reservoir sands are the first four, with a combined thickness of 130 feet. This is 87 percent of the total aggregate thickness of sandstones. These percentage values are posted on the isolith map, and percentage contours are sketched as shown by dashed lines in the figure. In the case illustrated the interval used is 25 percent.

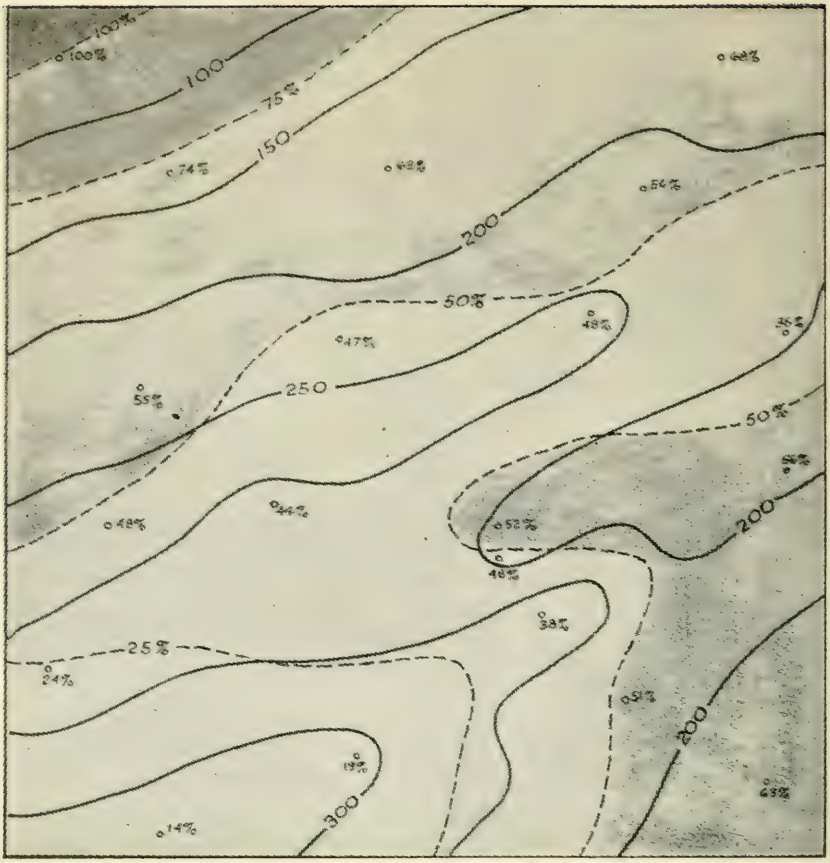


FIGURE 24-40. Sandstone isolith contours with shading according to percentage of sands more than 25 feet thick.

The map is somewhat easier to read if color or shading is used between the percentage contours.

A sheet of tracing paper is now placed on the map and fastened with drafting tape. The total thickness of effective sand is computed on the basis of total aggregate thickness and percentage of effective sand, and these values are plotted on the overlay. The overlay is then contoured as in Figure 24-41. This map shows by contours the thickness of effective reservoir sands that might be expected over the entire region.

Approximately the same result can be attained if only those sands adjudged to be of adequate thickness are considered in tabulating values from the logs. In this instance the isolith map itself is the effective reservoir map. It should be pointed out, though, that this artificial classification might yield values which would be difficult to contour or which would give erroneous trends. By following the procedure set forth, all significant sands are dealt with in the isolith map so that more reliable thickness *trends* are established. The overlay map is then contoured according to the general grain of the sandstone-isolith map. It is assumed that the thick and thin trends of the selected reservoir sands will correspond in a general way to the pattern of distribution of the entire sand content of the section.

In order to decipher the geologic history of a region in which major uplifts and severe truncation have occured, it is often necessary to reconstruct by isopach contours the original thicknesses of strata that have been entirely eroded away.

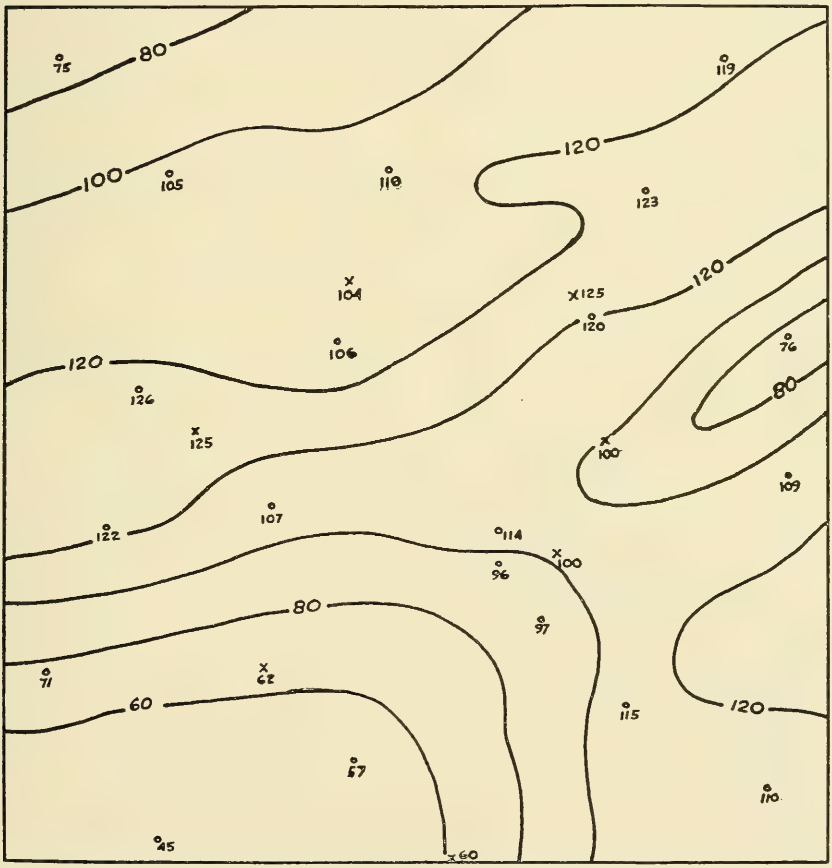


FIGURE 24-41. Map showing aggregate thicknesses of reservoir sands more than 25 feet thick.

A map that shows the restored thicknesses of rocks is called a *palinspastic* map (fig. 24-45).

Figure 24-42 shows an isopach map of a series of limestones and dolomites. Uplifts on which none of the sediments are present occur in the northwest and northeast quadrants. From the constant rate of thickening into the basinal regions, it can be inferred that the uplift in the northwest predates the sediments represented by the isopach contours, or that erosion has been uniform over the entire region. The axis of this uplift extends far to the southeast from the granite area. The contours tell a different story about the uplift in the northeast quadrant. The extremely high rate of thinning along the flanks and the abrupt termination of the axis show that the sediments were truncated and probably

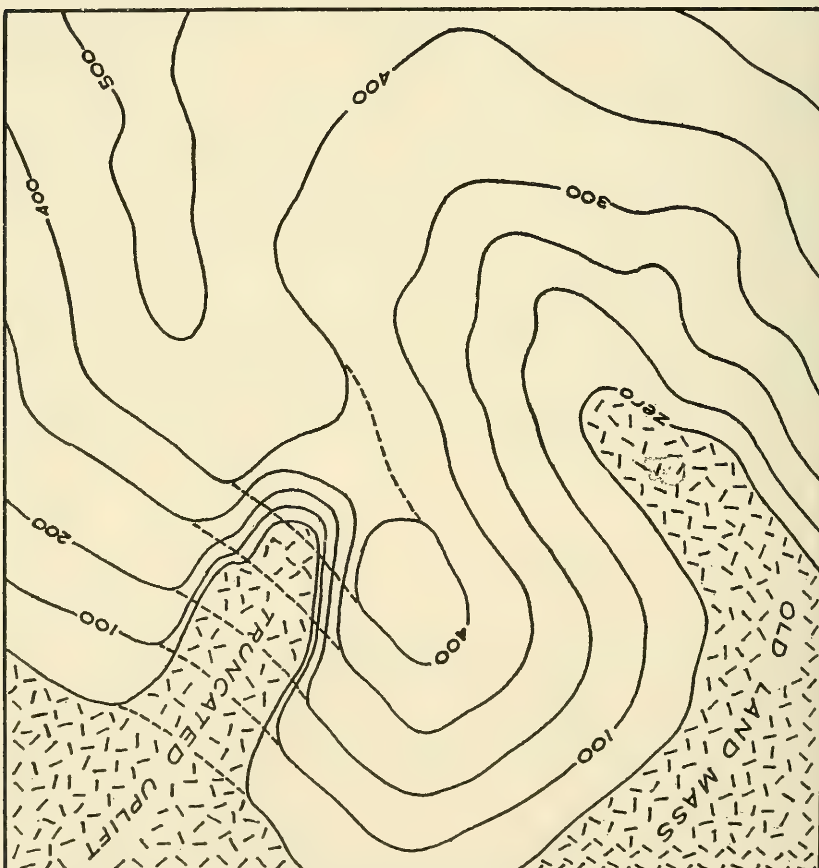


FIGURE 24-42. Isopach map showing reconstruction of thickness contours over a young, truncated uplift.

extended across the nose at an earlier date; therefore, this uplift is younger than the sediments. The restored thickness contours are shown as dashed lines, which represent the thicknesses of the limestone series before truncation.

The relatives ages of the two uplifts shown in Figure 24-43 cannot be determined from the behavior of isopach contours representing the flanking sedimentary rocks. Therefore, a lithofacies map is compiled, as shown in Figure 24-44. It can be seen that the facies trends conform to the general outline of the granite area in the southwest corner, but are unaffected by the one in the northeast. From the lithofacies it can be assumed that the uplift in the southwest predates the sedimentary series and contributed clastic materials. The northeastern uplift obviously is younger than the sediments.

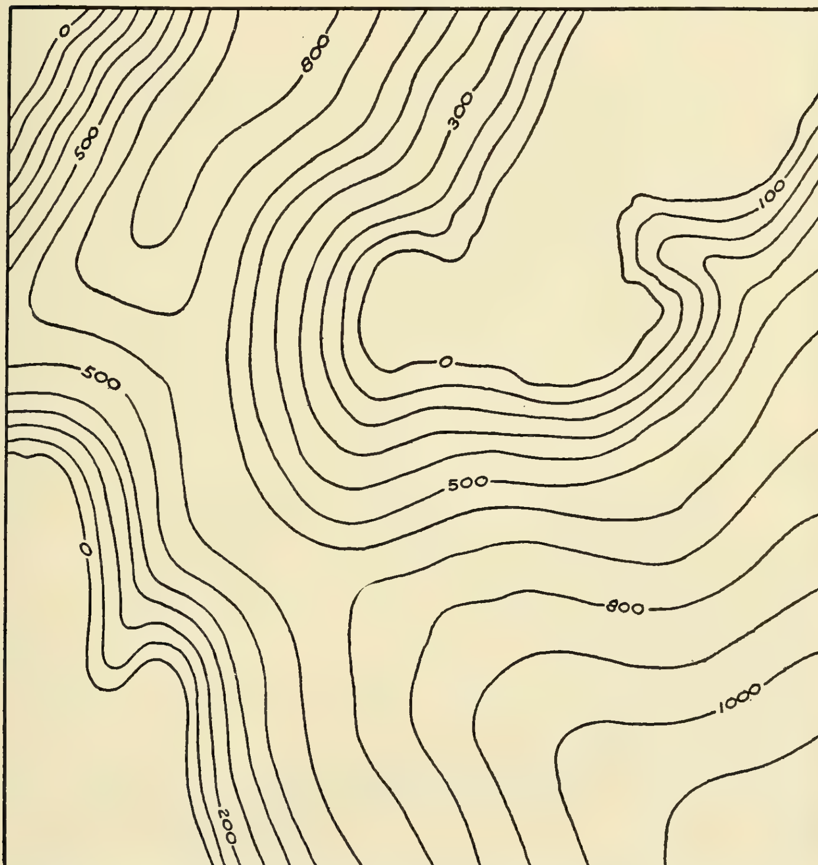


Figure 24-43. Isopach map used in construction of palinspastic map of Figure 24-45.

MODELS

Peg Models

The peg model is a device sometimes used to illustrate and study structural and stratigraphic conditions during the development of oil fields. It enables the geologist to view the behavior of the formations in three dimensions and is often a most useful tool in solving knotty structural problems. Peg models are not ordinarily used in broad regional work, especially where wells are widely separated, but are better

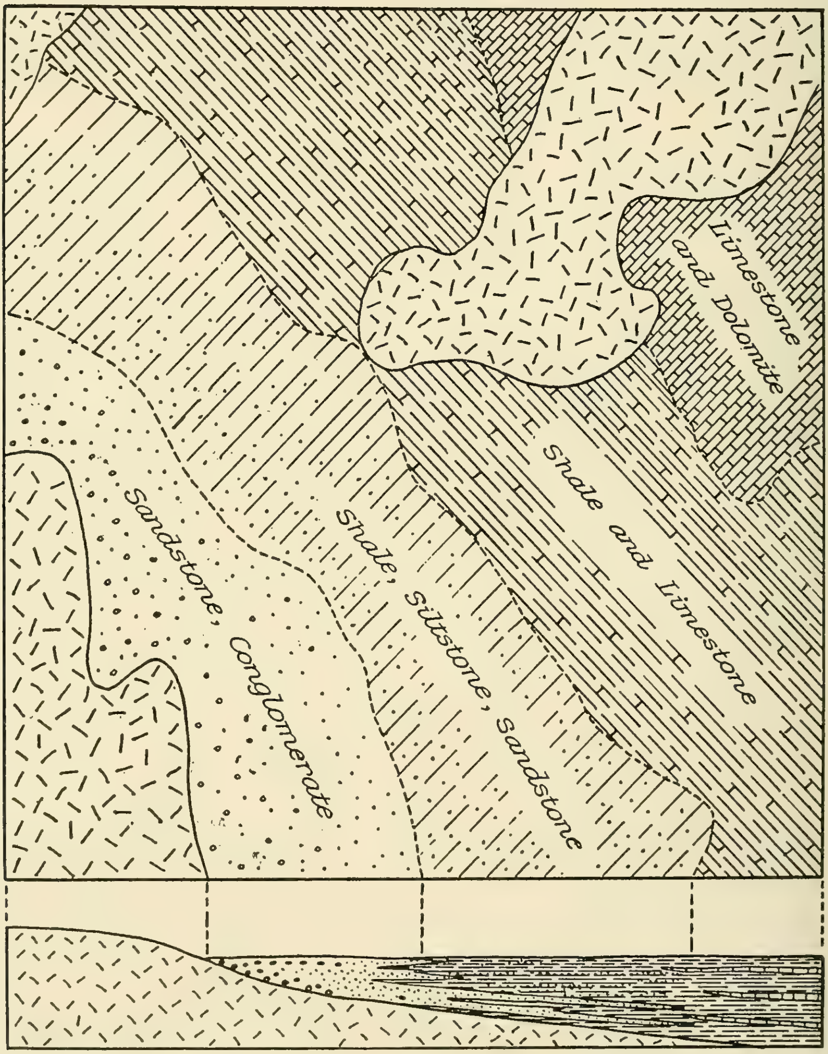


FIGURE 24-44. Generalized lithofacies map showing granite uplifts of different ages.

adapted to detailed subsurface studies of localized areas where well control is abundant. The principal objection to peg models is that they are bulky, occupy much floor space, and cannot be moved readily.

Figure 24-46 shows a peg model of a simple dome. The base into which the pegs are inserted should be made of wood not less than 1 inch thick. This base is painted, usually white or buff, and section and township lines and other desirable surface-map features are drawn on it to the scale selected for the model. At the location of each well, a ¼-inch hole is drilled almost but not entirely through the base. Ordinarily, a ¼-inch iron rod is used for the pegs, which, in turn, are to represent the wells.

The plane of the board is the elevation datum for the model. This assumed elevation should be somewhat below that of the lowest bottom-hole elevation in the field. Thus, if the lowest bottom-hole elevation is 2300 feet above sea level, then the model might be constructed with the base elevation at 2000 feet.

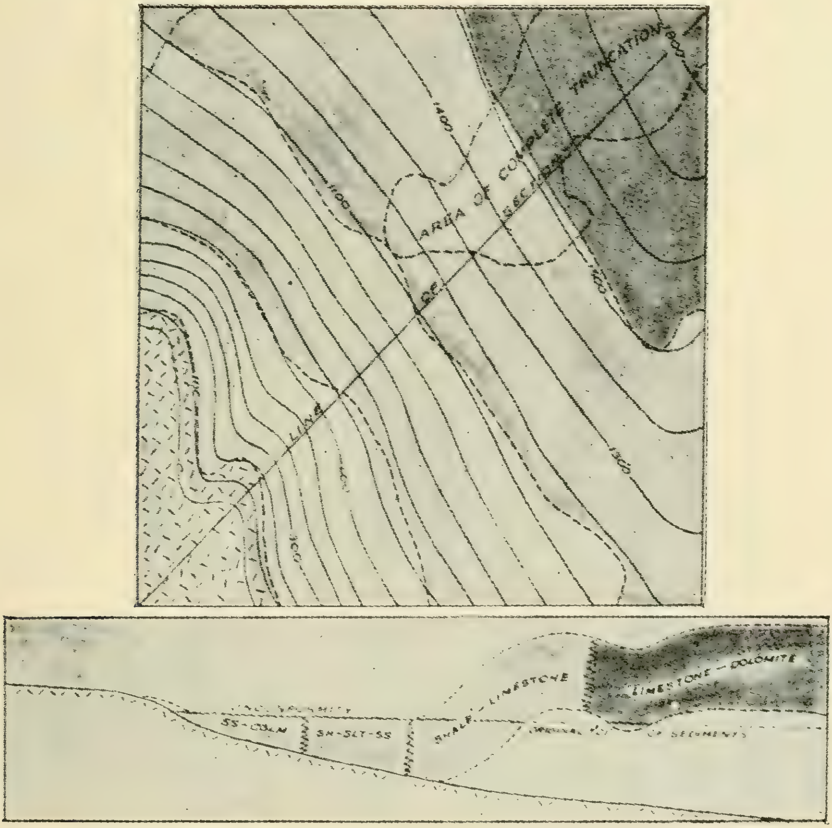


FIGURE 24-45. Palinspastic map showing thicknesses restored by means lithofacies and isopach maps.

The rods are cut to lengths equal to the surface elevations of wells on the vertical scale selected, plus an amount equal to the depths of the holes into which they will be mounted. The formations penetrated by the wells are represented on the rods by bands painted in different colors.

After the rods are cut, painted, and set in their respective locations, the formation tops from well to well are shown by strings colored the same as the formations which they represent, as indicated in Figure 24-46. When all the rods are connected with the colored strings, the planes of the formations can be seen in their approximate relationships to one another. Of course, this illustrative method does not permit showing the curved surfaces of the structures, but it does suggest them in the sloping planes of which the strings are elements.

Solid Models

A solid relief model of a structure can be made in much the same way as a topographic relief model, if there is a good structural contour map of the area.

The contour map is used as a pattern. Since the map will be cut during the construction of the model, several copies should be on hand. Sheets of pressed-fiber wallboard are cut with a coping saw along each contour line, as shown in Figure 24-47*B*. When the first sheet is mounted on the base, the next higher contour is transferred to it, as shown by the dashed line in the figure cited. This may be done with one of the uncut maps and carbon paper. The transferred

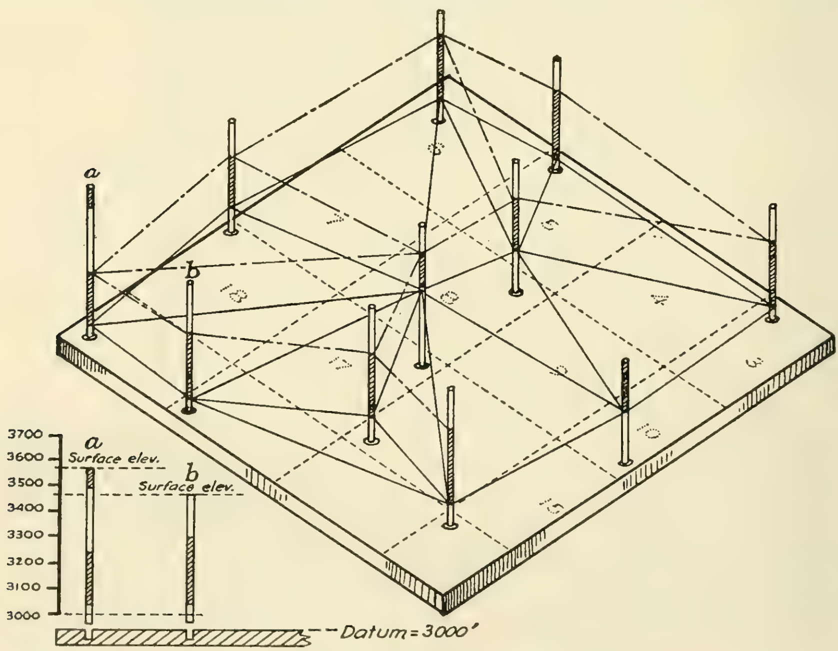


Figure 24-46. Peg model of a simple dome.

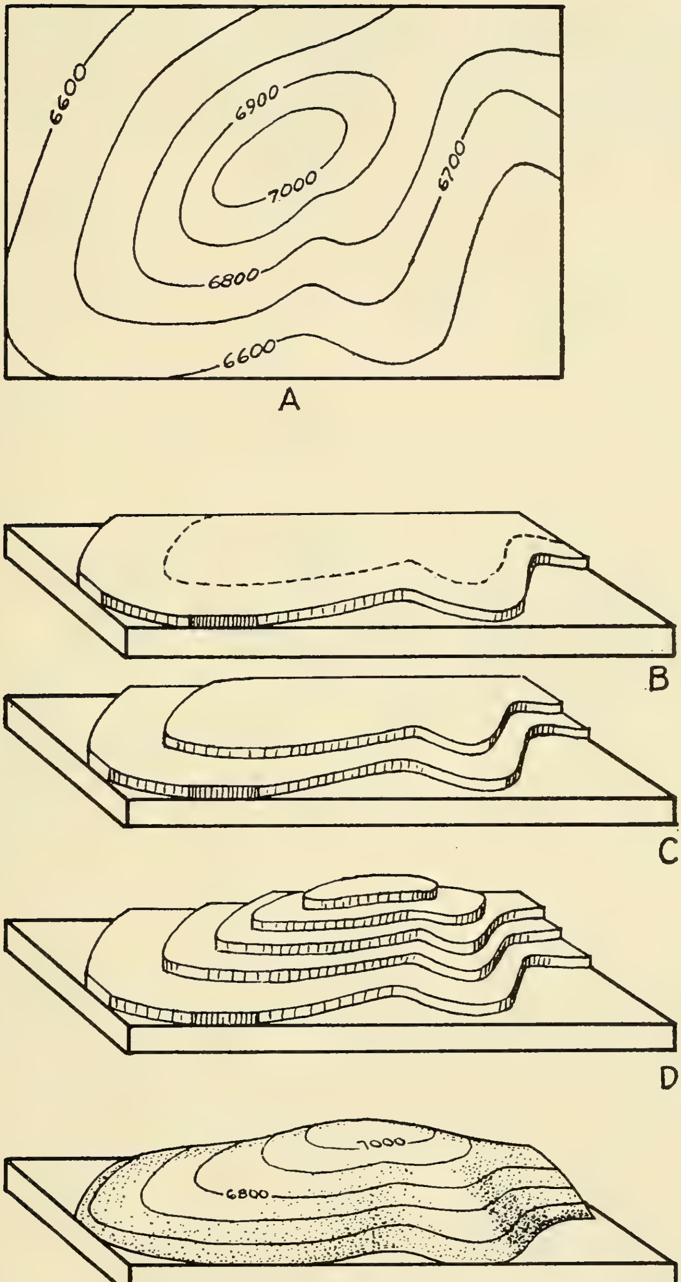


FIGURE 24-47. Solid relief model of a structure.

line serves to fix the position of the next fiber-board sheet, as in Figure 24-47*C*. When all the contours have been cut and the sheets are firmly nailed down, the skeleton of the model will look like Figure 24-47*D*. This skeleton should be partly waterproofed with several coats of shellac, after which it may be covered with plaster of Paris, papier-mâché, or a similar material. Care must be taken to use only a sufficient thickness of the covering material barely to cover the edges of the fiber-board contours, or the accuracy of the model may be impaired.

If it is desired to show the structure contours on the finished model, pins may be stuck in the edges of the blocks before the covering material is applied. The pins will later serve as guides for sketching the contours and can easily be pulled out when they have served this purpose.

The solid model is used principally as an aid in teaching. Unlike the peg model, it cannot readily be altered to incorporate structural data that might become available at a later date, and for this reason the solid model is generally used for illustrative purposes.

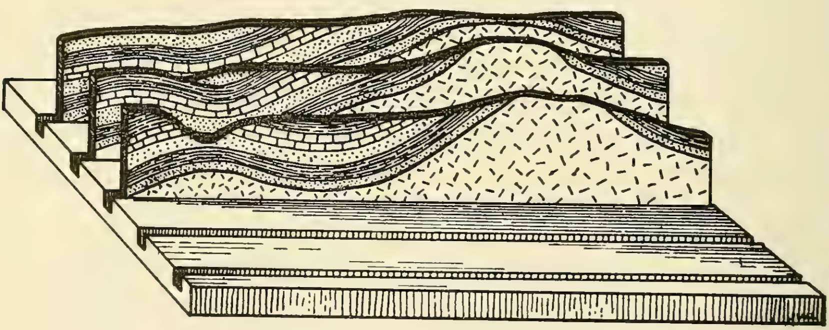


FIGURE 24-48. Models of parallel structural cross sections.

Section Models

The section model is a series of parallel cross sections drawn or painted on any thin, rigid, boardlike material (fig. 24-48). These sections in turn are set in properly spaced slots in a solid base. A thick, hard cardboard is satisfactory for the sections, although transparent material such as cellulose acetate or Plexiglass is sometimes used because it is then possible to view one cross section through another. The section model is more practicable than the solid model in that any one of the sections can easily be removed and revised without affecting the others.

Miscellaneous Models

Various types of working models have been made for the purpose of studying the behavior of fluids in permeable reservoirs. Others have been constructed to determine the deformation of rocks under different kinds of stresses. The models discussed earlier are similar to maps in that they are built as an aid to visualizing geologic conditions as they exist today. In contrast, the working models attempt to determine the series of events that bring about these conditions.

ILLUSTRATIONS

Cross Sections and Projections

While subsurface maps of all kinds show geologic conditions in essentially horizontal planes, sections show the details of stratigraphy or structure in vertical planes. Neither the map nor the section, alone tells the whole geologic story; and, for this reason, any exhaustive subsurface investigation of an area must use both sections and maps. Sections fall into two general groups, structural and stratigraphic, although there are types that incorporate both stratigraphic and structural features.

Figure 24-49*A* is a structure section plotted on a natural scale. This type of section does not attempt to show any structural features between the wells, such as might be indicated on structural maps of the area, but does show the difference in elevation of the formations at the wells.

Figure 24-49*B* is a stratigraphic section along the same line, also plotted on a natural scale. In a stratigraphic section one continuous stratigraphic horizon is selected as a reference line or datum; this line is drawn straight across the sheet. All other formational boundaries are referred to this line according to the thicknesses of the formation. Thicknesses are usually indicated by numbers starting with zero at the datum horizon. In the drawing cited above, the datum is the top of the Permian, and thickness numbers start at this point. Figure 24-49*C* shows the same stratigraphic section, but with the vertical scale, two times as large as the horizontal.

Exaggeration of the vertical scale, in either a stratigraphic or structural section, introduces certain distortions which may suggest nonexistent geologic conditions. This is particularly true in straight-line sections like those shown in Figure 24-49. Sometimes the vertical scale is exaggerated as much as 50 times. Structural sections with greatly exaggerated vertical scales tend to exhibit thinning of the formations where dips are steep, giving the effect of attenuation on the flanks of structures and thickening on the tops of anticlines, bottoms of synclines, and at any other places where the dips are flat. Rates of dips are likewise increased according to the amount of exaggeration of the vertical scale.

Despite the distortions resulting from exaggerating the vertical scale, there are also some advantages. Local structures in areas of very low dips may not be discernible in sections drawn to natural scale. Where dips are extremely low, there is little distortion except in the rates of the dips; therefore, some increase in the vertical scale is obviously desirable.

The sections just discussed are drawn along a series of short lines connecting the wells. Occasionally, it is possible to select wells situated on a nearly straight line, but more often the line of section is somewhat zig zag. This often gives erroneous impressions of actual geologic conditions, because the line of section at some places may parallel the structural strike or stratigraphic strand lines, whereas at others it may cut across these lines. Where the distribution of wells permits a choice of those to be used in the section, an effort should be made to select the ones that will give the straightest line of section.

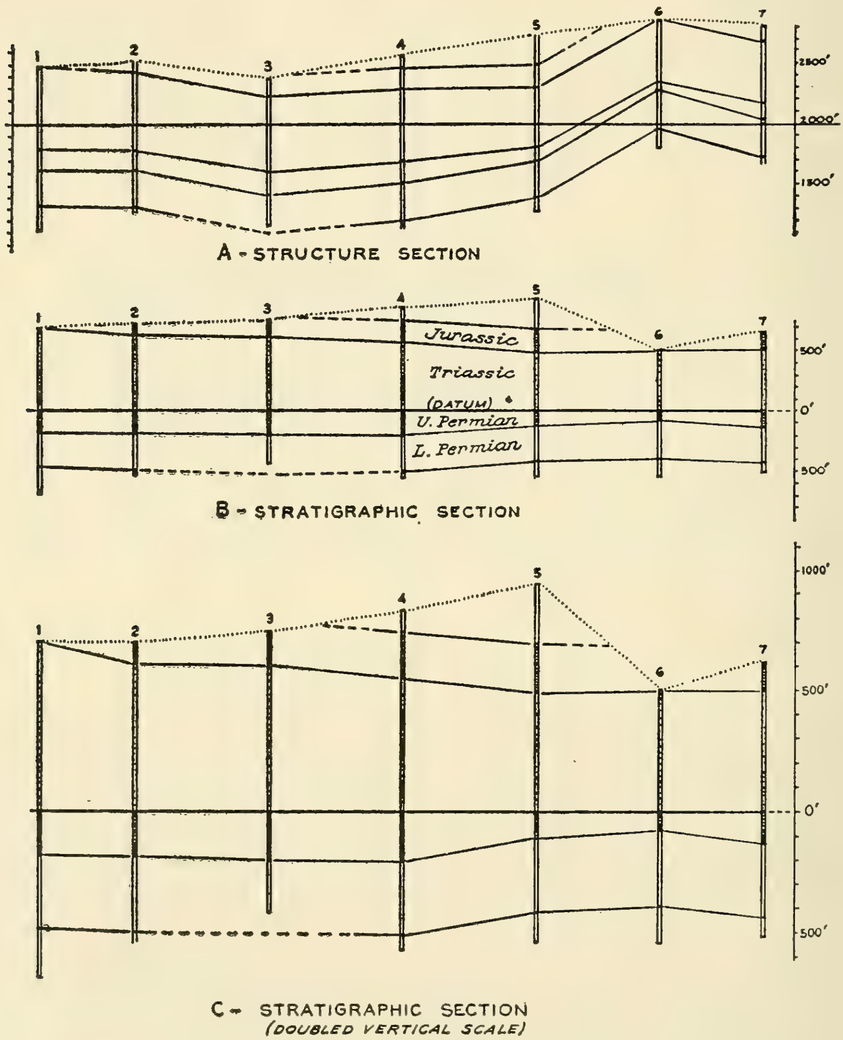


FIGURE 24-49. Structural and stratigraphical sections.

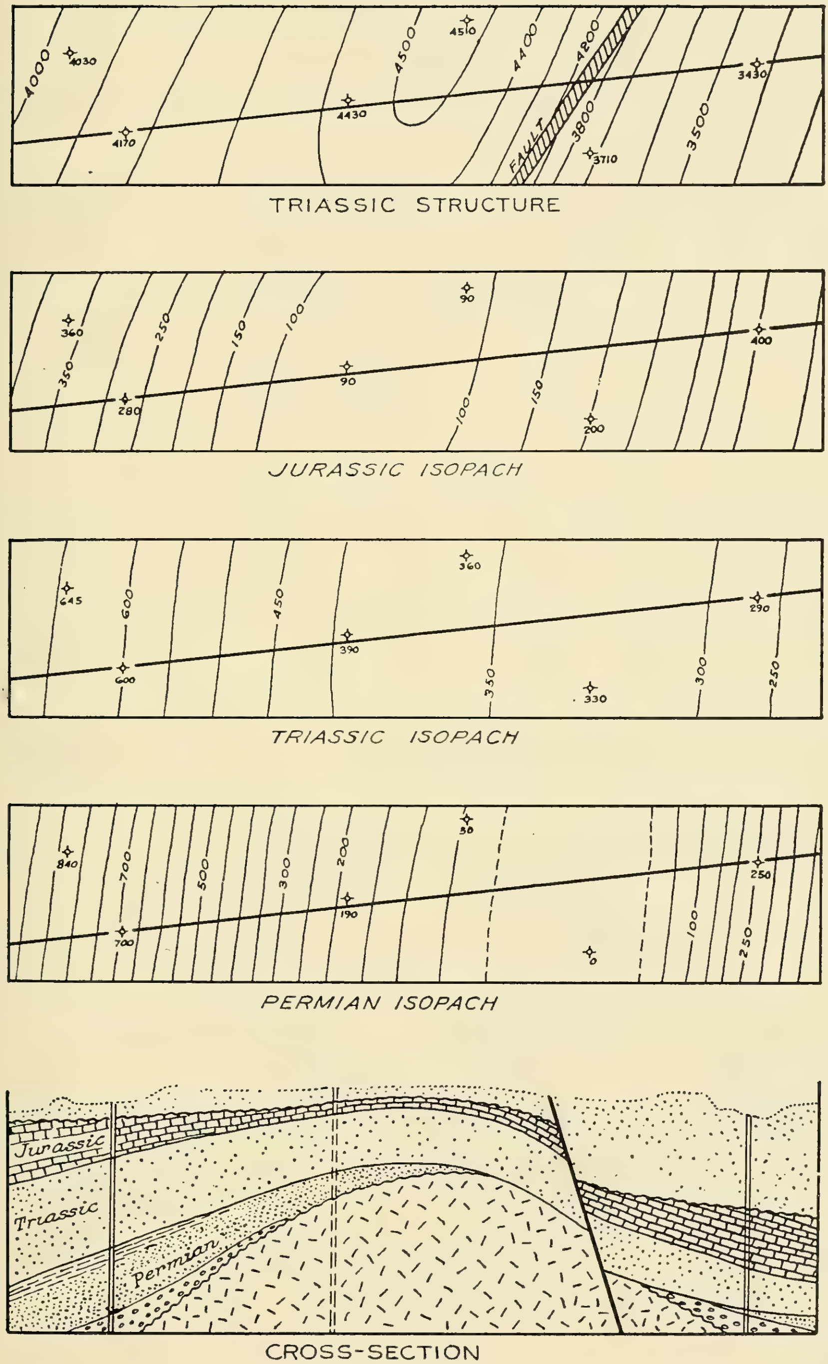


FIGURE 24-50. Structural and isopach maps and cross section based on data taken from maps.

The best way to construct a true cross section involves the use of structural and isopach maps. Incidentally, such a section is an excellent check on the accuracy of a complete series of isopach and structural maps.

Figure 24-50 consists of one structural map and three isopach maps; the cross section is drawn on the basis of data taken from the maps. The method employed is as follows:

The line of section is drawn on each of the maps. In the case illustrated, this line passes through two of the wells and very near a third. The wells cut by the line of section can be shown in the cross section.

From the Triassic structural map a structural profile is drawn by using the elevations indicated where contours cross the line of section. The profile should be plotted on a natural scale unless the structural relief is extremely low. This profile is, in a sense, the structural datum of the cross section. It is also the reference line from which all succeeding geologic boundaries are drawn.

Now, from the Jurassic isopach map, thicknesses of the Jurassic along the line of section are obtained where isopachs cross the line. The thicknesses are plotted above the structural profile. The top of the Jurassic is then drawn through these points. The same procedure is followed with the Triassic and Permian isopach maps to draw the contacts stratigraphically below the structural reference line. The surface profile can be taken from a topographic contour map.

Figure 24-51*A* is a log map. It consists of well logs plotted to any adaptable scale in their respective locations on the map. The example shows the bases of the logs at the map location, but they may be plotted with the tops of the logs or any selected continuous stratigraphic horizon on the logs at the respective map points. When the logs are plotted, they may be joined by formational correlation lines, as shown.

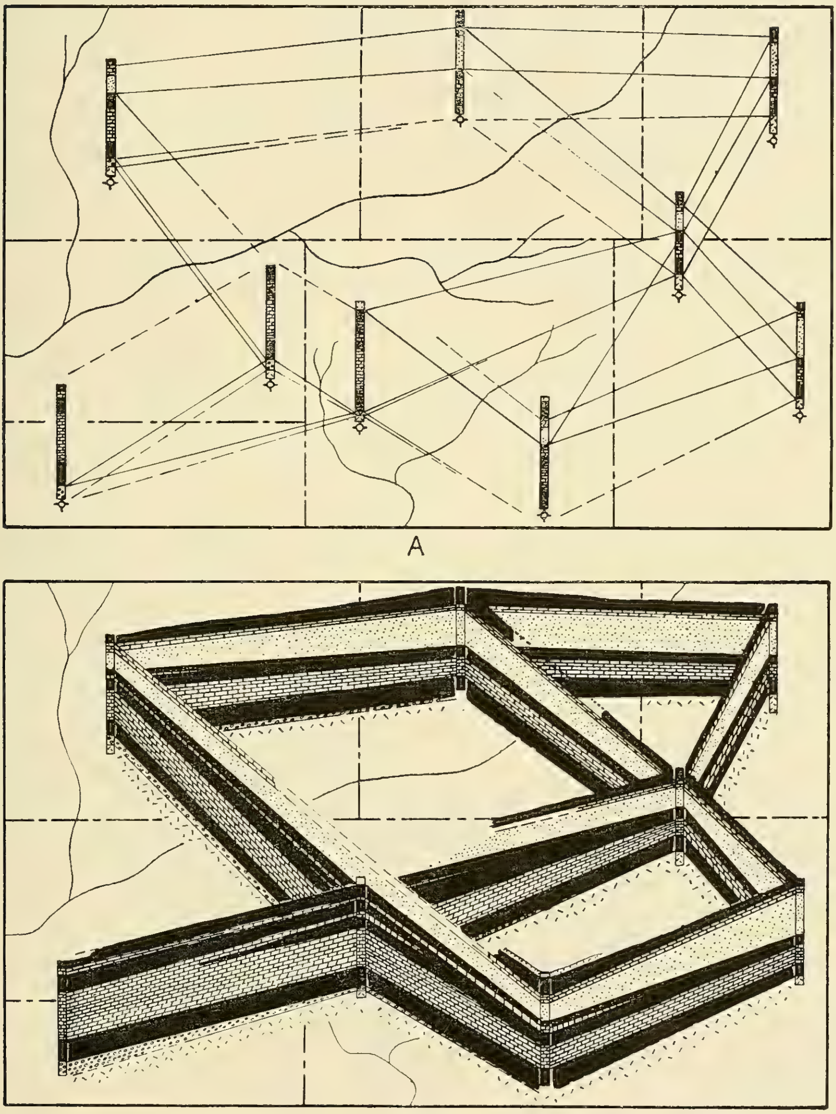
Figure 24-51*B* is a panel map of the same area as that shown in the log map. In the panel map it is possible to show changes in lithologic facies, pinchouts, and other stratigraphic conditions occurring between the wells.

As only the front panels are shown in their entirety, they should be drawn first. In other words, the lowermost panels on the page are drawn, then the next higher, and so on to the top of the drawing. Panels joining wells along north and south lines are omitted, for they would appear only as single lines on the map.

The stratigraphic isometric projection is a special adaptation of the panel map. Figure 24-52*A* is a base map with a few principal streams and well locations. Figure 24-52*B* is the isometric projection made from this map.

In order to construct an isometric projection, it is necessary to have the map contained in a rectangular grid, unless the land lines, as in the case illustrated, provide such a grid. This grid, which may be drawn to any scale, regardless of the scale of the map, serves only the temporary purpose of placing map features correctly on the perspective drawing. Instead of a grid, coordinate scales were used in the figure, and parallels were drawn from the section lines.

The isometric projection is referred to as a 20- or 30-degree projection, depending on the perspective effect desired and the construction necessary to produce this effect. An isometric projection is always less than 45 degrees;



A

B

FIGURE 24-51. *A*—Log map. *B*—Panel map.

for a 45-degree projection is simply a map rotated 45 degrees on the sheet, and there is no foreshortening as in any perspective drawing.

In Figure 24-52*B*, the upper corner of the projection, is the northeast corner of the map. The east and west sides of the map are drawn at an angle of 30 degrees to the horizontal (in a 30-degree projection). This, the northeast and southwest 90-degree angles of the map become 120 degrees, and the south-

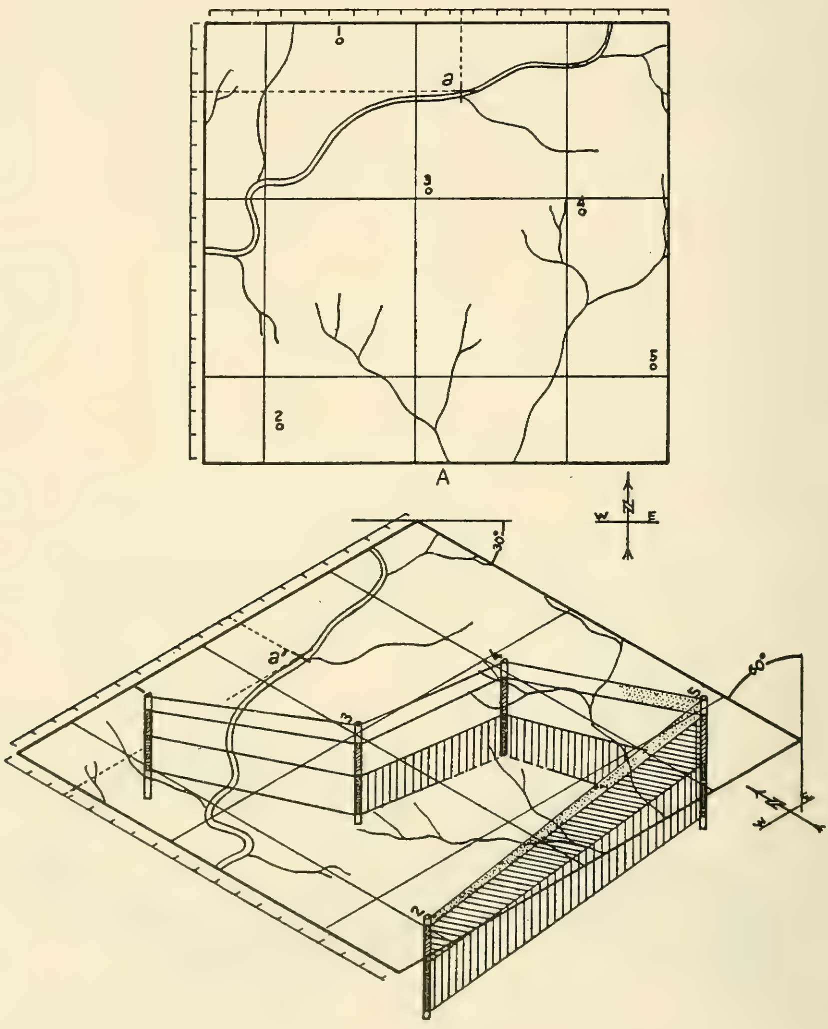


FIGURE 24-52. Stratigraphic isometric-projection drawing.

east and northwest corners become 60 degrees in the projection. All north-south and east-west lines are parallel, and scaled distances between map points along these parallel lines are the same as on the map. Scaled distances in any direction except parallel to these lines are either greater or less than those on the map. Obviously then, in order to transfer map information to the projection, it is necessary to do so by means of coordinate measurement. Point *a* on the map is 10.5 units (any scale) east of the northwest corner of the map and 2.8 units south. Point *á* on the projection is the some number of units along corresponding lines. Any point on the map can be accurately located on the projection by scaling along coordinates; and this procedure must be followed in locating a sufficient number of control points, such as the confluences of streams, road intersections, and well locations, to insure accurate sketching between these points.

When the wells are located on the projection, logs are plotted at the locations on a vertical scale adapted to the scale of the projection so that the desired effect is attained. The isometric base is considered as a level plane. Therefore, if it is assumed to be at sea level and the logs are placed so that the sea-level point on the log is adjacent to the map location, then the panels will represent the structure. Of course, if the bottoms of the wells are above sea level, then the plane of the projection should be at some datum high enough to cut all the wells.

The plane of the projection may also be considered a stratigraphic datum, i.e., the top of a formation; and all the logs are then placed with this horizon at the location point. Another common practice is to draw subsurface geology entirely below the plane of the projection and surface geology above. The principal objection to this method is that the drawing may have neither a structural nor a stratigraphic datum. The panel projection in Figure 24-52*B* is drawn with the plane at the top of a formation; this, therefore, is a stratigraphic projection. The panels have not been completed in order to permit a clearer view of some of the map features.

Block Diagrams and Other Illustrations

It is of the utmost importance that the geologic concepts developed as a result of studies in structure or stratigraphy be shown in some manner that is most comprehensible to those who have only occasional contact with the projects. Maps and cross sections sometimes fail in their purpose of conveying to others certain complex geologic conditions, mainly for the reason that each is two-dimensional—one in the horizontal plane, the other in the vertical. Block diagrams effectively combine the features of both maps and sections and are, therefore, an indispensable mode of illustration.

Geologic block diagrams are constructed according to certain principles of projection and perspective. Space here does not permit going into all the details of block diagrams: only the fundamental principles necessary for constructing the simplest illustrations can be given.

The two upper blocks in Figure 24-53 are examples of the simplest projection. All opposing sides are parallel to each other, and, because of this feature, they can readily be drawn with a drafting machine or a triangle and straightedge. Distances along the front and back edges and all lines parallel to these edges are drawn to the scale of the map. Distances along the sides and parallel to the sides may or may not be to the scale of the map; but, in any case, the scale is constant along these lines. This type of block is sometimes called a parallelogram block, but it is essentially an isometric projection. The block may be drawn with any desired degree of tilt. The high-angle block, as illus-

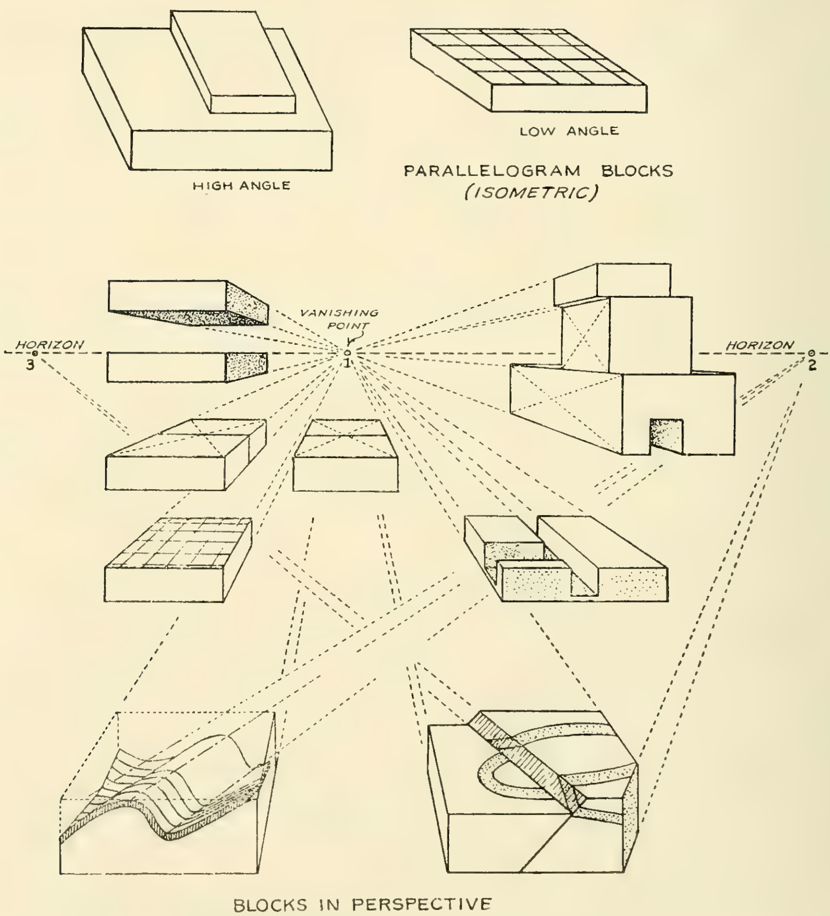


FIGURE 24-53. Geologic block diagrams.

trated, should be used in illustrations requiring considerable details in the horizontal or map plane. Low-angle blocks are more effective where it is desired to emphasize the vertical sections in two directions. The high-angle block may be drawn so that the scale is the same along the two horizontal coordinates; but the low-angle kind should use a somewhat smaller scale along the front-to-back lines in order to produce a more realistic effect of perspective. The scale is reduced along this coordinate in the section lines drawn on the low-angle block in the figure cited.

Because of the simplicity of the isometric block, it is the one most commonly used in geologic illustrations. A number of examples appear in this chapter to demonstrate various features. Since this type of block is not a true perspective figure, the distant or upper end appears to be larger than the front or lower end, and the block, therefore, is somewhat awkward and distorted. Despite this fact, it is the most generally useful of the block diagrams.

The lower set of blocks in Figure 24-53 is drawn in one-point cabinet perspective. In this construction, lines forming the sides of the block and all others parallel to these converge into a single point called the vanishing point. The vanishing point lies on the horizon, which, in turn, is level with the observer's viewpoint. Any pair of parallel lines not parallel to the construction lines of the block also converge to a point on the horizon but to the right or left of the vanishing point of the block. The blocks shown in the figure present one face without perspective distortion directly toward the observer. This is a departure from a true or natural perspective drawing, except in the one case where the vanishing point lies directly above or below the block. Such a view does not expose the sides of the block. All other positions of the block would, in natural perspective, require some convergence in the frontal face; but since this would unnecessarily complicate the drawing of geologic features, the front of the block is made a true rectangle, and the sides and top, quadrilaterals.

The perspective block, although somewhat more diffcult and tedious to draw, is also more natural in appearance. Effects of towering heighs and deep depressions and low or high vantage points are readily attained by mechanical drawing methods.

Figure 24-53 shows blocks in various positions relative to the observer. The uppermost blocks are above the horizon and, therefore, above the observer's position. The block in the upper left is placed so that the bottom is exposed to view. The stack of three blocks on the right is drawn so that the base of the stack is somewhat below the observer's eyes, and the top at a considerable height above. Note that the second block in the left-hand series lies on the horizon, and, consequently, the eyes are exactly in the plane of the upper surface. The two blocks below, which are successively lower, expose more of the upper surface.

The geometric centers of the faces are shown in several instances at the intersections of the diagonals. It is quite apparent that the center of the block is always to the rear of the scaled midpoint. This is illustrated in the sectionized block on the left where the spacing between section lines is progressively less from front to back. This fact must be kept in mind when geologic features are transferred from maps to blocks in one-point perspective.

The geologic diagrams at the bottom of the figure illustrate the use of secondary vanishing points. The block on the left shows an anticline and two synclines, the axes of which are parallel and trend diagonally across the block. Since the block is drawn in perspective, these parallel lines must also be shown with the same degree of convergence; therefore, it is necessary to select a new vanishing point on the horizon (*2* in the figure). When the folds are constructed according to the convergence of lines into this point, the perspective in the geologic features will be the same as that in the block.

The lower-right diagram utilizes three vanishing points, as indicated by the construction lines. Point *3* is the focus for the lines bounding the fault plane, and *2* controls the lines cutting off the corner of the block.

Figure 24-54 shows a structural map and one-point perspective block of the same area. Both have been shaded with a pencil to emphasize the structural relief. A contour map shaded in this manner is called a shadow-graphic map. There are two methods for attaining the shadow effect. The simplest is by hand shading, as mentioned. In both the map and block it is assumed that the source of light is the upper left-hand corner. All structural surfaces facing this corner receive the greatest amount of light, and those sloping toward the lower right-hand corner bear the heaviest shading. High points have high lighting; low areas, dark shadows.

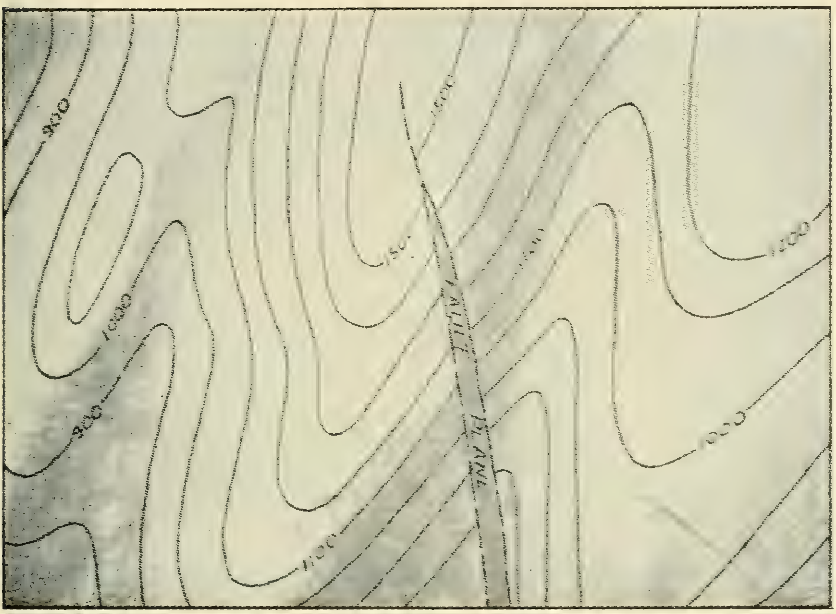
A more cumbersome method consists in first soaking a contoured map until it can be moulded into ridges and depressions conforming to features shown by the contours. This may be done by working the softened map over a mass of wet papier-mâché. When the modeling is completed, the shadow-graphic map is obtained by photographing from directly above with one source of light, preferrably from the upper left-hand corner. Obviously, this is a much more tedious method than shading the map with a pencil.

Coloring of Geologic Maps

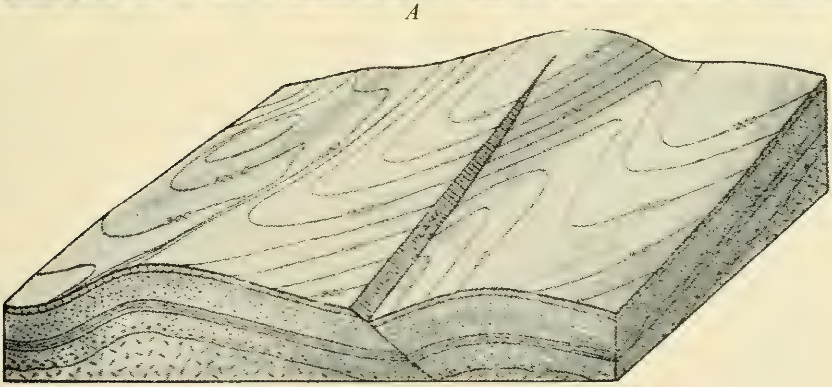
Many kinds of maps require coloring, and since the maps that are made by commercial organizations are not reproduced in color by printing proceses, they must be colored by hand. When several copies of a map are needed, the coloring of the prints may develop into a burdensome task. For this reason, it is desirable to be familiar with a number of different methods in order to select the one which will best satisfy the needs of the project.

Maps are usually colored for practical reasons, not merely for embellishment. The main purpose in using colors is to increase the legibility so that significant features can be seen at a glance. Because of this fact, color contrasts are more desirable than color harmony with low contrasts of tone or hue. On the other hand, clashing colors should be avoided if pleasing effects are desired.

The U. S. Geological Survey and various state surveys use only certain colors for rocks of specific geologic ages; one color range for Paleozoic rocks,



A



B

FIGURE 24-54. *A*—Shadow-graphic structure map. *B*—One-point perspective block diagram.

another for Mesozoic, and so forth. Subdivisions within a main group are designated by patterns, such as ruling, stippling, and others. Since it is not practicable in most cases to use patterns on hand-colored maps, the color standards set up by the Geological Survey cannot be maintained. However, some consistency can be practiced, and if the colors are well chosen, the result in the finished maps will justify the discrimination exercised in the selections.

For paleogeologic maps, the coloring is more effective if the darkest tones or most striking hues are used for the oldest rocks, the palest pastel tints being reserved for the youngest systems or formations. As an example, the following associations would be effective:

Cretaceous	shades of yellow
Jurassic	shades of brown, generally medium to light
Triassic	pink, orange
Permian	light red
Pennsylvanian	light and dark grays
Mississippian	shades of blue
Devonian	light green
Silurian	lavender
Ordovician	reddish-purple to bluish-purple
Cambrian	dark greens of different hues
Pre-Cambrian	dark reds, some pattern

A similar arrangement can be determined when the colors are to represent a number of units within one system. However, an effort should be made to avoid representing a geologic system on one map by a certain color, and on another map by a different color.

In the different types of lithofacies maps, the main rock types should always be shown by certain colors. It is advisable to follow as closely as possible the color system used to represent lithologies on colored well logs, which, in turn, varies among oil companies. This practice greatly simplifies the interpretation of the lithofacies map by those already familar with the color adaptation in lithologic logging. Some variations are necessary in mapping, particularly where colors of the rocks, as in shales, are important features of the facies; but in general, the associations given in Figure 24-34 are adequate.

When colors are to be used on the map, some consideration must be given to the kind of prints that are to be made from the line tracing. Thin-paper translucent prints, such as sepias, are not satisfactory. The best prints for coloring are blue-line or black-line Ozalids on medium- to heavy-weight rag-stock paper. Van Dyke positive prints on heavy paper can be hand colored with good results, but they are more difficult to work with than the Ozalids. Photostats are still more difficult because of the natural gloss and hard, impervious surface. Linens are not suitable for coloring.

Several methods of hand coloring are in use, each having peculiarities that are advantageous under certain circumstances.

Crayon Pencils

These wax-base colored pencils are applied as evenly as possible over the surface of the sheet with particular attention being given to boundary margins. When all areas of one color have been covered, a fine, even tone of clear color is achieved as follows: It is necessary to have at hand a few paper charcoal stumps (blenders) of sizes 4 to 8, which can be purchased at any artists' supply store. The stump is dipped in white gasoline, benzine, or dry cleaning fluid; and, after the excess on the surface has soaked in, the stump is rubbed over the penciled area with a light, fast circular motion. The solvent dissolves the wax and carries the pigment into the absorbent paper. This process produces a water-resistant color on the map. When the solvent in the map paper has evaporated, a second application of color and solvent may be applied if darker tones are desired. A dark tone can be graded imperceptibly into a lighter one in this manner; or two colors may be so graded, one into the other. After the wax-pencil coloring has been treated with solvent, it has no tendency to rub off.

Indelible Pencils

The indelible colored pencil, sometimes called a water-color pencil, is soluble in water but is relatively unaffected by the aromatic solvents used with the wax-base pencils. The method of application is identical to that described above, except that the blender is used dry. The indelible pencil spreads easily and rapidly with either a dry stump or a wad of facial cleansing tissue or blotting paper.

For temporary maps, the indelible pencil is better than the crayon pencil. The indelible pencil is especially useful in preliminary work which may have to be revised, for the color can be removed with a soft rubber eraser even after blending with a stump. On the other hand, it rubs off on clothing or other maps, and changes to brilliant hues on contact with even small amounts of water. Perspiration from the hands will cause unsightly blotches on the map; therefore, when there is danger of this blotching, colored portions should be covered while work is in progress. The color can be fixed, or set, by spraying with Krylon liquid plastic.

Water Color

Transparent water colors may be applied as a wash on Ozalid prints, but they are difficult to use and may cause appreciable shrinkage and distortion of the map scale. The air brush is an efficient and generally satisfactory method, although it may cause some shrinkage. When using the air brush, one should mask all the map except the portion that is to be colored. Heavy wrapping paper is used for this purpose. For lithofacies maps, slotted stencils can be cut from stiff paper or cardboard. The stencil is laid over the exposed part of the map; and the air brush, set on a wide spray, colors the map in bands. When the first color is dry, the stencil is offset one space and the second alternating color is applied. If three color bands are required, two stencils are needed. They are placed one on top of the other and are shifted until the desired exposure of the map surface is attained.

Printers' Ink

Colored printers' inks provide a means of coloring large areas with a uniform tone, with no evidences of overlap. Since the inks have a grease base, there is no scale change in the map. The method is easy and fast, and the results are nearly as flawless as printing. This method was developed by Geophoto, Inc., Denver, Colorado.

The viscous printers' ink is thinned with about three parts of mineral spirits to one part of ink. Thorough mixing is essential.

The color is applied with a sable artists' round brush of size 6 to 12, depending on the size of the area to be colored. All of the surface must be covered, but need not be spread evenly. When an area of 5 or 6 inches square has been covered, a double thickness of facial cleansing tissue is laid flat on the moist color and patted down so that the excess ink is absorbed. A pad or wad of the tissue is used to wipe and rub all free color from the map. When the color is extended, the edge previously colored is overlapped. There will be no visible overlap when this is wiped with the cleansing tissue.

Better results can be expected if the border areas are colored first with a medium-sized brush not too heavily charged with ink. A larger brush may be used in the central parts. The darkest colors are applied first. If this procedure is followed, no overlaps will show, even where two different colors are involved.

There is no satisfactory means of removing the printers' ink from the paper. Therefore, considerable care must be taken that the color is applied correctly. Maps colored by this method may be soaked in water for cloth mounting without danger of disturbing the colors. Colored areas will take colored pencils within a few minutes, but they should be given several hours or days to dry before ink lines are attempted.

The printers' inks can be mixed to obtain an infinite variety of shades. Pastel tints are obtained by mixing the colors with the white transparent base. Colors must be mixed before they are applied to the map because, as suggested earlier, the paper becomes charged with the first color applied and is, thereafter, resistant to further applications. Within reasonable limits, the viscosity of the color has no effect on the hue or tone on the map: i.e., the same color is obtained with either a thin or thick mixture.

Pencil Shading of Isopach Maps

Shadow-graphic maps and the methods of drawing them have been described. Similar use of a soft pencil can add much to the over-all legibility of isopach maps, as shown in Figure 24-55. Thick areas are darkest, thin ones lightest. About four different tones are most effective. The texture of the map paper determines to a considerable extent the hardnesses of pencils that should be used. On medium-weight Ozalid black-line paper, hardnesses of 2B to 2H are satisfactory. The toning is accomplished by rubbing the graphite with a charcoal stump blender, as described for indelible colored pencils. The change in tone should be made along contours at equal thickness intervals. In the figure cited,

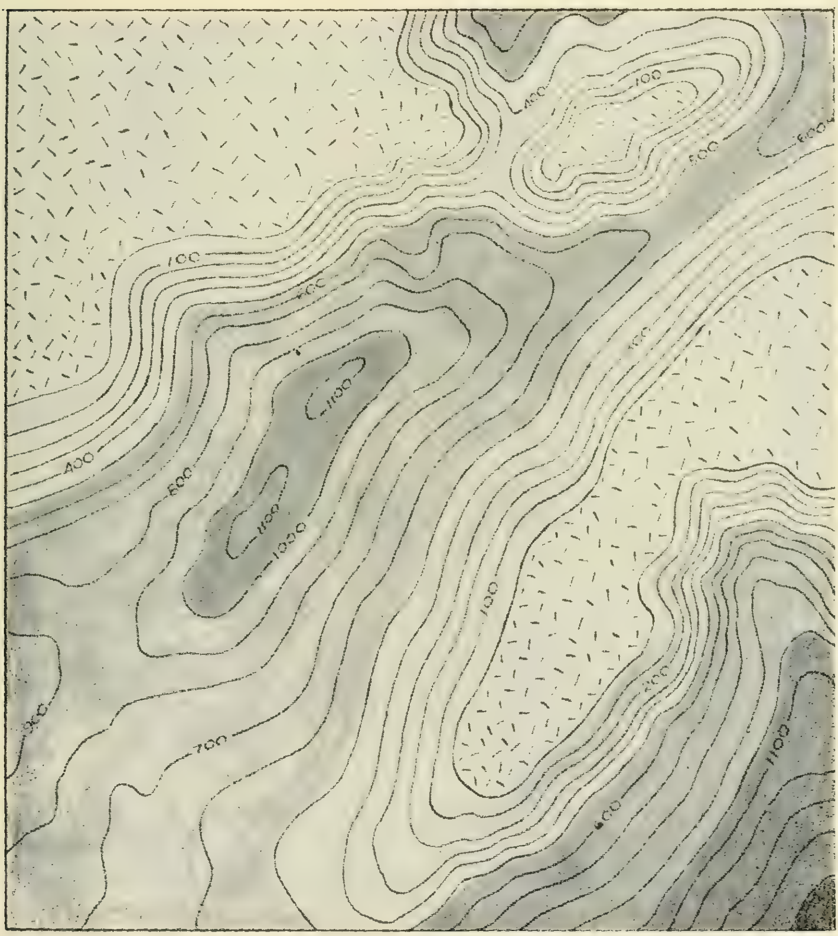


FIGURE 24-55. Isopach map shaded with pencil to emphasize areas of thick section.

this interval is 500 feet, although the map is contoured on a 100-foot interval. The difference in this type of shading and that employed in shadow-graphic maps is that the latter suggests an illuminated model, whereas the former is shaded strictly on the basis of contour values.

Reproduction of Maps

Most maps and other geologic drawings must be reproduced by one means or another. Better prints can be expected if the draftsman is aware of the peculiarities and limitations of the more common processes of reproduction. An exceptionally well-drawn map may lose much of its effectiveness in reproduction if certain principles in drafting are neglected.

The so-called photocopy processes depend upon the transmission of light through the medium upon which the map is drawn. The lines and figures drawn on the map prevent the light from passing through and exposing those portions of the sensitized printing paper. It is, therefore, desirable for the lines to be opaque and the medium transparent or highly translucent, and the quality of prints will depend largely on the degree to which these conditions are met. Obviously the best reproductions will be obtained from drawings made in black drawing ink on transparent material, such as cellulose acetate. Lines drawn with colored, waterproof inks may look well on the original map, but they are liable to be indistinct or discontinuous on the print because these inks are not opaque to the intense lights of the printing machines. If colors must be used on originals to be reproduced by photo processes, the water-soluble types are more satisfactory. When extremely thin lines are necessary on acetate or similar, thick materials, it is better if they are inked on the back side where they will be in direct contact with the printing paper. Thin lines on the upper surface are likely to burn out in printing because of diffraction along the edges of the lines.

Since the necessary exposure time is longer with more opaque media, such as thick vellum or tracing paper, the opportunity for light leakage along thin lines is greater.

Photocopies can be made from penciled originals; but it is essential to maintain considerable contrast between the opacity of the tracing material and the lines. For this reason thin tracing paper with a toothy texture combined with pencils which make very black lines gives the best results. It is somewhat difficult to make reproducible maps with penciled lines on acetate and tracing linen.

Good photostats can be made from copy that is too weak to reproduce by light-transmission processes. Better reproductions are obtained from originals having high line and background contrasts. Generally speaking, prints by Ozalid and Van Dyke methods are better than photostats for hand coloring by methods described earlier. Photostat prints are more receptive to colored pencils if they are rubbed with drafting pounce or some other very fine abrasive. Of the processes discussed above, only the photstat permits a reduction or enlargement of the original scale.

Maps and drawings for publication should be drawn to a slightly larger scale than that desired in the reproduction so that the inevitable irregularities occurring in lines, figures, or lettering will be reduced or eliminated in the reduction of scale. Over-all proportions, however, are not improved in the reproduction; in some cases, faulty proportions of map features are even more evident in the reduced reproduction.

Plain black-and-white drawings, that is, black lines on a white or blue background, are the most economical to reproduce. These drawings can be reproduced by several different processes, the principal ones being offset, engraving, lithograph, or metal lithograph. The line drawings in this chapter are reproduced by the zinc plate or offset process.

Shaded drawings, such as Figures 24-54 and 24-55 are half-tone reproductions. All reproductions of photographs are made by one type or another of the half-tone process. The half-tone methods are appreciably more expensive than black-and-white line work. Drawings shaded by stippling, ruling, or hachuring, as in the central blocks of Figure 24-53, can be reproduced by black-and-white methods.

Reproductions in color are expensive and should be avoided when black-and-white or half-tone methods can be substituted. A separate plate must be made for each primary color used. In the printing, the paper must be run through the press for each of the color plates.

Drafting of Maps

The effective drafting of geologic maps of all kinds is too important to be neglected entirely, even though the subject cannot be fully discussed here. There are two main reasons for drawing subsurface maps, and which is the more important depends largely upon circumstances.

The first reason is obvious to those engaged in the technical phases of subsurface investigations: the various types of subsurface maps are in a sense geological tools. The technician must appraise the various data which he has processed by means of contours so that trends, gradients, anomalies, and other phenomena are developed. Subsurface geology is three-dimensional, and *must* be developed by a method which takes the three dimensions into account. Only contoured maps can do this in a continuous manner. Contour maps are quantitative, and any geologic condition that can be reduced to numbers can also be contoured. Examples are thicknesses, elevations, grain sizes, porosities, permeabilities, temperatures, percentages, and ratios of any two or more rock constituents. In addition to mapping geologic conditions quantitatively, it is often necessary to show the chemical, mineralogical, or physical characters of the rocks by a means which depicts only the qualitative aspects, as in certain lithofacies maps. It is only when all the properties are mapped that the subsurface geologist can grasp the complete geologic picture.

The second function of geologic maps, which is often as important as the first, although it affects the geologist only indirectly, is the presentation of mappable geologic phenomena to those having only slight acquaintance with the subject. Often the executives who control the operations of organizations know little about the details of subsurface methods and lack the technical training and experience necessary for an understanding of the geologist's working maps. Since the men who manage and control the operations of exploratory companies must be kept informed on the geologic developments, it devolves upon the geologist to construct maps that convey the essence of his work in a direct manner, without the details so necessary in the working maps. Maps that are to be used for the purposes described above should emphasize the ideas and conclusions of the geologist, not merely present or evaluate geologic data.

The methods of coloring maps have been described. But other features of map construction are equally important. It is difficult to show a number of different classes of geologic data on one sheet without some confusion of lines or areas. Therefore, the legibility of the map should be the principal guide as to how much can be shown to advantage. Several factors influence the legibility of a map:

(1) Standard symbols—The U. S. Geological Survey as published sheets of standard symbols for geologic maps. These symbols should be used wherever applicable because they are more likely to be understood by everyone using the map. If it is necessary to invent a symbol to indicate some subsurface feature, this sheet of standard symbols should be consulted to avoid using a figure which is standard for some other feature. The size, form, and weight of symbols should be kept uniform, except in special cases where a variation in the size or mass of the symbol denotes a corresponding variation in the size or importance of the feature shown.

(2) Line weights—The careful grading and uniformity of line weights have much to do with the legibility and general appearance of the map; for example, line weights should grade downward from state boundaries, county boundaries, townships, sections, etc., despite the fact that certain of these are further distinguished by various sequences of short and long dashes.

(3) Lettering—The lettering on most maps is done largely by LeRoy or Wrico lettering sets, which produce letters in a wide variety of sizes and line weights in both slanting and vertical styles. The presentation of the map is greatly enhanced when the choice of letter sizes and weights is made judiciously. Before any lettering is done, the features should be classified, and proper templets selected for each. The same templet will produce different-appearing letters when

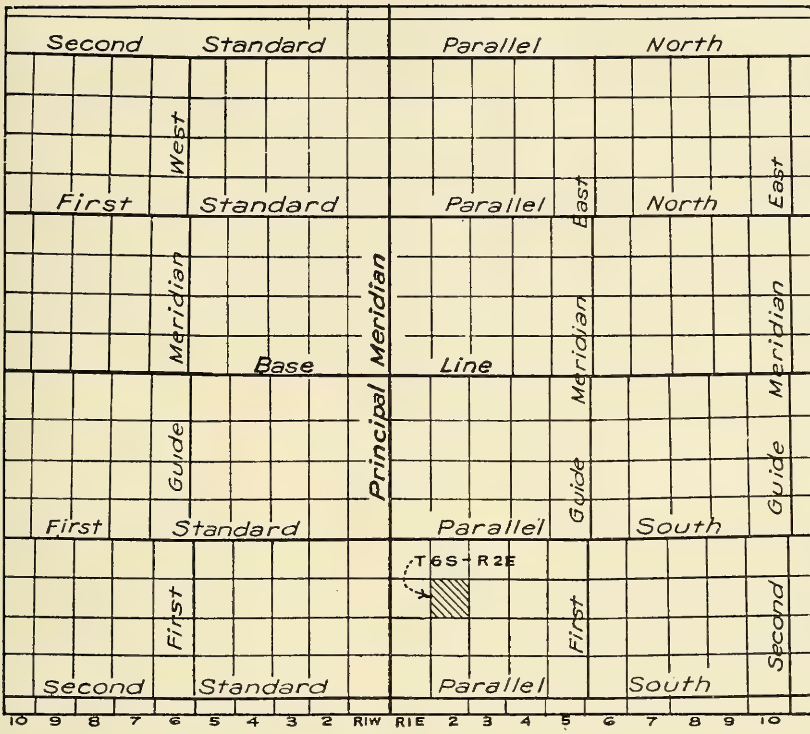


FIGURE 24-56. Plat illustrating principles of township and range designations.

pens of varying sizes are used. Likewise, the spacing between letters is important in the appearance of a name. It is good practice to employ wide spacing for linear features and compressed spacing for locations of small areal extent. Slant letters should be used for surface hydrographic features, such as streams or lakes, and for descriptive or explanatory notations. Vertical letters in upper and lower case are used for geologic and geographic names. Large letters made with fine pens are less troublesome in obscuring control points or figures than are small letters in heavy lines. Lettering on vertical lines should read from the bottom upward. Lines that are even slightly inclined to the left at the top are lettered from the top downward. In other words, the letters should never be even slightly upside down.

(4) Legends and explanations—All symbols whose meanings might be misconstrued should be fully explained in a legend. This precaution applies also to colors and colored lines that are not identified by notations where they occur. The best location for the legend is near the title of the map. It is bad drafting practice to place portions of the legend at several locations in the margins.

Using a name or a short explanation to identify a feature on the body of the map is better than using a symbol which must be explained in the legend. It is tiresome for the map reader to have to refer frequently to a legend in order to understand the map. Explanatory notes at the approximate location of the feature to which they refer can hardly be misconstrued and are less diverting than the seesaw reference to a legend.

(5) Geographic references—On a map which is well-planned and correctly drafted, it is not difficult to describe the location of any feature shown or to plot accurately new points of control. In other words, the map base should contain all the reference lines necessary for these operations. In subsurface work it is annoying to work on a map, of which base consists of only geographic coordinates (meridians and parallels).

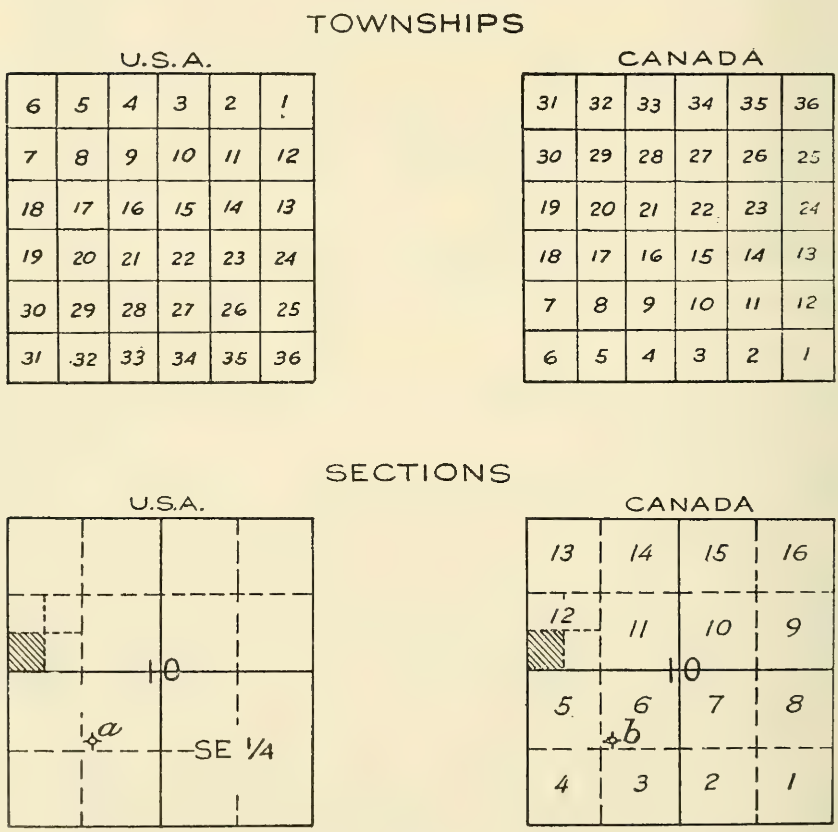


Figure 24-57. Plats showing subdivisions of United States and Canadian townships and sections.

Practically all descriptions of well locations refer to township, range, and section lines; and if these lines are not shown on the map, it is difficult to determine the correct locations. On very small-scale maps, township lines may be undesirable; but, since county lines are tied in to the "land net," they may be shown. It should be borne in mind that geographic coordinates are not lines surveyed and marked on the ground, but, rather, are the framework of the map projection. The subsurface geologist is concerned primarily with legal subdivisions of state and federal surveys; and all points of control will be located on the map by means of these surveyed lines.

Figure 24-56 illustrates the basic principles of the township system of land surveys. There are many deviations from these principles, but ordinarily only small areas are involved. In western Canada all townships are numbered north, beginning with township 1 at the international boundary. All ranges are east and west of one principal meridian located in the eastern side of Manitoba. Guide meridians are spaced about 30 townships apart and are numbered 1st, 2nd, 3rd, etc., meridians west.

Figure 24-57 shows the numbering of sections in United States and Canadian townships, and the subdivisions of the sections. Townships in Canada, like those in the United States, are composed of 36 sections, each approximately one mile square and containing 640 acres. The numbering of the sections is shown in the figure cited.

The Canadian system of designating the subdivisions of a section is more convenient than ours. The 1/16-section (40-acre) tracts are numbered from 1 to 16 according to the Canadian plan of numbering sections in the township. These subdivisions are called *Legal Subdivisions,* abbreviated *Lsd.* Thus, the shaded portion in the section diagram is described as SW¼ of Lsd. 12. According to our system the same tract is described as the SW¼ of the SW¼ of the NW¼, or SW SW NW. The location of a well situated at *a* is described as follows: SW SW NE SW¼ of section 10. In Canada the description (at *b*) is: SW SW Lsd. 6 of section 10.

For a number of years it has been common practice in western United States to make the footage location of a well according to multiples of 330 feet from surveyed land lines. Thus, a location described as 1650 feet from the west line and 1650 feet from the south line of section 10 would be in the SW SW NE SW¼ of the section, or the location of *a* in Figure 24-57.

Well-spotting templets, made from acetate of about 0.020 inch thickness, greatly facilitate the posting of maps. The templet is made with inked lines corresponding to the land lines shown on the map, with holes punched at the normal positions of well locations. The templet is registered over the land lines on the maps and the well is spotted by inserting a sharp pencil in a hole at the correct location.

Because of the fact that the surveying of public lands over the years has not been carried out in a continuously systematic manner, there are many duplications in the numbering of townships and ranges. Therefore, in addition to the township and range, the state and, in some instances, the county, must also be known before a location on the map can be made. For this reason, the state and county should be given in the location of a well.

Reprinted from *Subsurface Geologic Methods*, 1951, p. 894-967.

Chapter 25

STEREOGRAPHIC PROBLEMS

Hugh McClellan

Stereographic projection is an ancient and useful method for graphically solving geometrical problems in three dimensions. It has been widely used by crystallographers, but has been generally neglected by geologists; however, there is increasing evidence that geologists more and more are coming to appreciate the speed and convenience of the stereographic method, which can be applied to many problems of structural geology.

FIRST PRINCIPLES

Wulff Stereographic Net

Figure 25-1 shows the bottom half of a sphere, through the center of which a plane has been passed. The strike is northwesterly, and the dip is about 40 degrees southwesterly. The plane traces a great circle on the sphere, and points on the great circle have been projected to the zenith of the sphere. Dots indicate where these lines penetrate the equatorial plane along the arc of a circle. In like manner a family of planes, all with the same strike, but varying in dip, may be projected through the equatorial plane, producing the meridional arcs of the stereographic net (fig. 25-2).

Vertical planes that may be passed through the hemisphere perpendicular to the north-south axis trace small circles on the spherical surface. These small

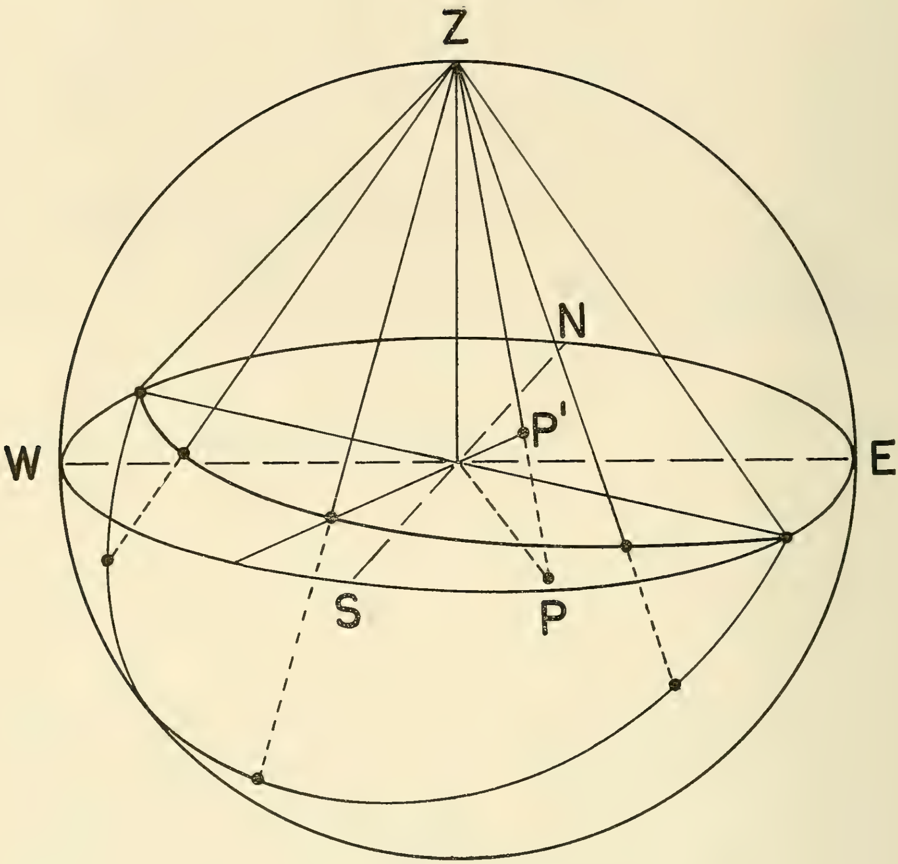


FIGURE 25-1. Sphere showing stereographic projection of plane by both cyclographic and Polar projection.

circles, when projected to the zenith, will trace arcs on the equatorial plane and form the latitudinal lines observed on the stereographic net.

The beginner will note that to measure angles along a radius in the plane of the net it is first necessary to orient the radius to a north, south, east, or west direction. The small distortions in most stereographic nets may cause an error of one or even two degrees, but this is well within the limit of accuracy of the basic data.

Polar Projection

In Figure 25-1 the plane is represented on the stereographic net by a line through the center in the direction of strike and an arc which is the projection of the great circle cut by the plane. This is cyclographic projection. However,

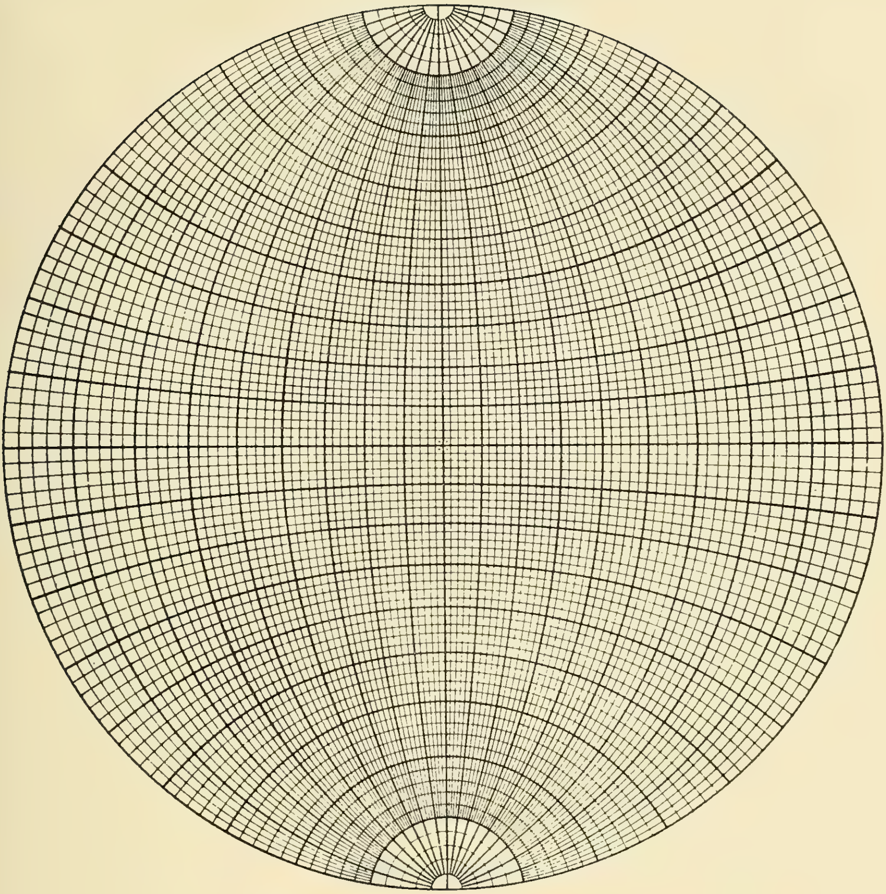


FIGURE 25-2. Wulff meridional stereographic net drawn to 2° intervals.

the plane can be represented equally well by its normal, which passes through the center of the sphere. In Figure 25-1 the intersection P of the normal with the surface of the sphere is projected to the zenith. Where this line penetrates the equatorial plane, the point P′ locates the normal on the stereographic net. If the plane has a dip of 40 degrees, the normal will have a hade of 40 degrees. On the stereographic net, the dip of the plane will be measured inward from the circumference, whereas the hade of the normal will be measured from the center outward.

Polar Stereographic Net

Various types of stereographic nets have been developed for special purposes, but the Wulff net (fig. 25-2) is most generally used. If planes are passed

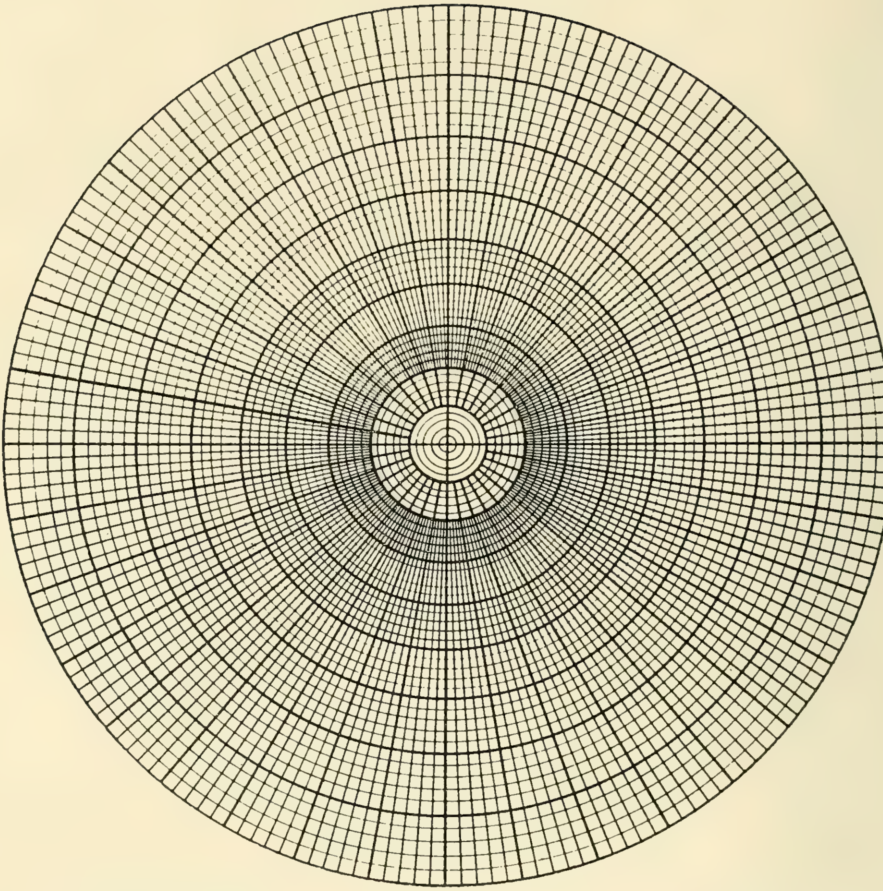


FIGURE 25-3. Wulff Polar (equatorial) stereographic net drawn to 2° intervals.

through the hemisphere perpendicularly to a vertical axis, these will project into the equatorial plane as concentric circles, forming the Wulff polar stereographic net (fig. 25-3), which is useful in some structural problems.

APPLICATIONS OF STEREOGRAPHIC NET IN STRUCTURAL GEOLOGY

Intersection of Two Planes (1)

One of the basic problems of structural geology is the determination of the line of intersection of two planes (Bucher, 1944; Nevin, 1949; Wallace, 1950; Phillips, 1954). A fault plane or a vein may intersect a bedding plane; surface or subsurface attitudes of beds may be known on opposite flanks of an anticline. In these instances it may be desirable to find the attitude of the line of intersection of the planes involved.

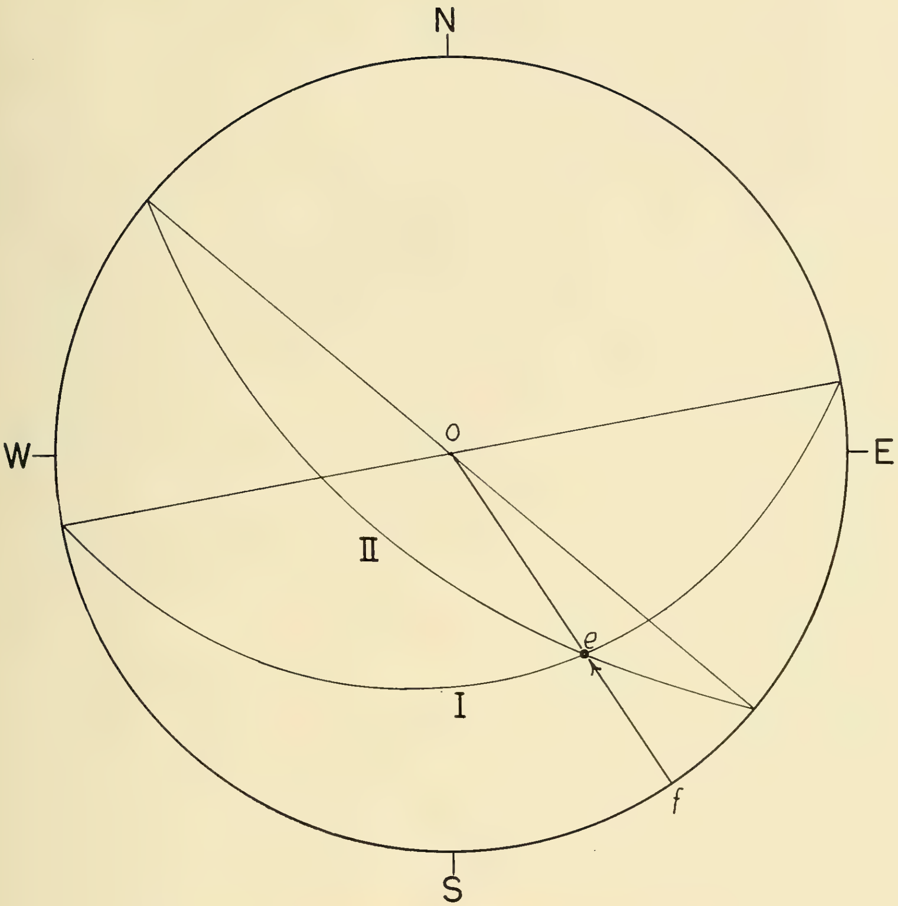


FIGURE 25-4. Stereogram of intersection of two planes.

To solve the problem by descriptive geometry requires some 12 lines accurately drawn with straight edge and protractor. With the stereographic net, only a piece of tracing paper and a pencil are necessary.

We shall suppose that plane I dips 30 degrees on azimuth 170 degrees and that plane II dips 60 degrees on azimuth 220 degrees. Figure 25-4 is the stereogram of the two planes by cyclographic projection. It is seen that the planes intersect at the center and at a point on the surface of the lower hemisphere. With the stereogram oriented to north, the line *o-f* gives the direction of the required intersection of azimuth 147 degrees. The position of point *e* when measured from the circumference of the net along the E-W or N-S line, fixes the plunge of *o-e* at an angle of 27 degrees.

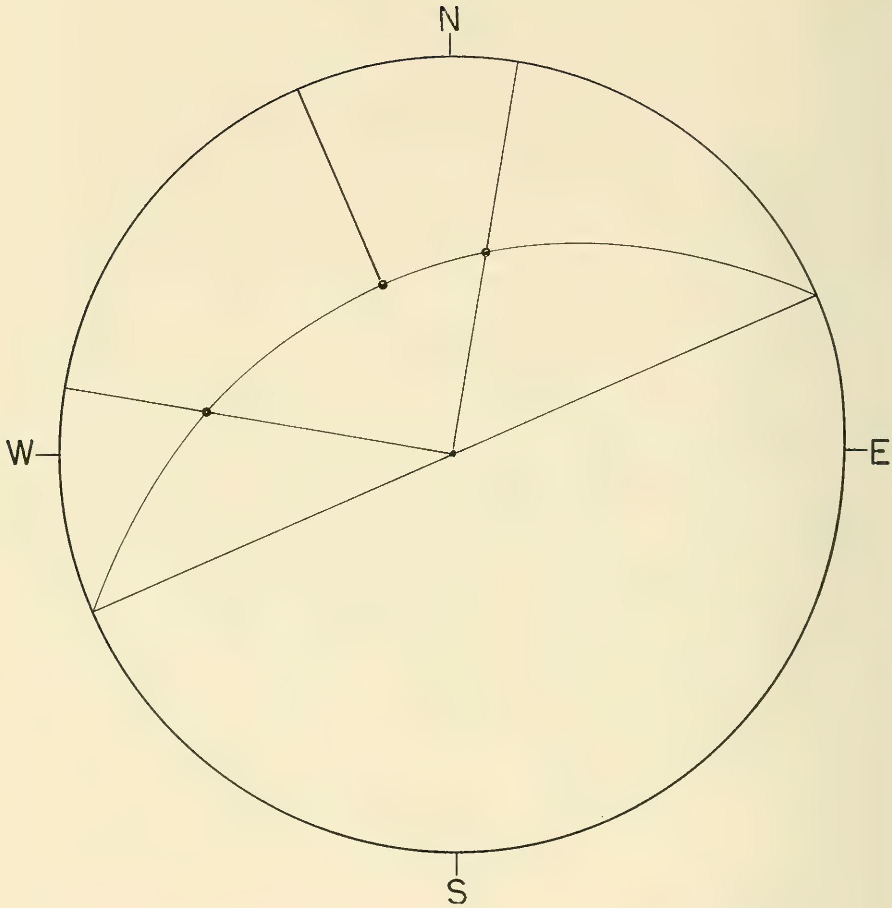


FIGURE 25-5. Stereogram of determination of true dip from two apparent dips.

True Dip from Two Apparent Dips (2)

This procedure has many applications (Nevin, 1949; Phillips, 1954). In subsurface work, two cross sections may be drawn at an angle to each other in order to intersect various oil wells. Neither section is at right angles to the strike of the beds, so that both sections show only apparent dips. For example, in Figure 25-5 one apparent dip is 35 degrees in a direction north 10 degrees east, whereas the other is 25 degrees north, 80 degrees west. The apparent dips are laid out on the stereographic net in their respective directions and marked by dots, which lie on the projection of the great circle made by the bedding plane. The stereogram is rotated until both dots lie on one of the meridional great

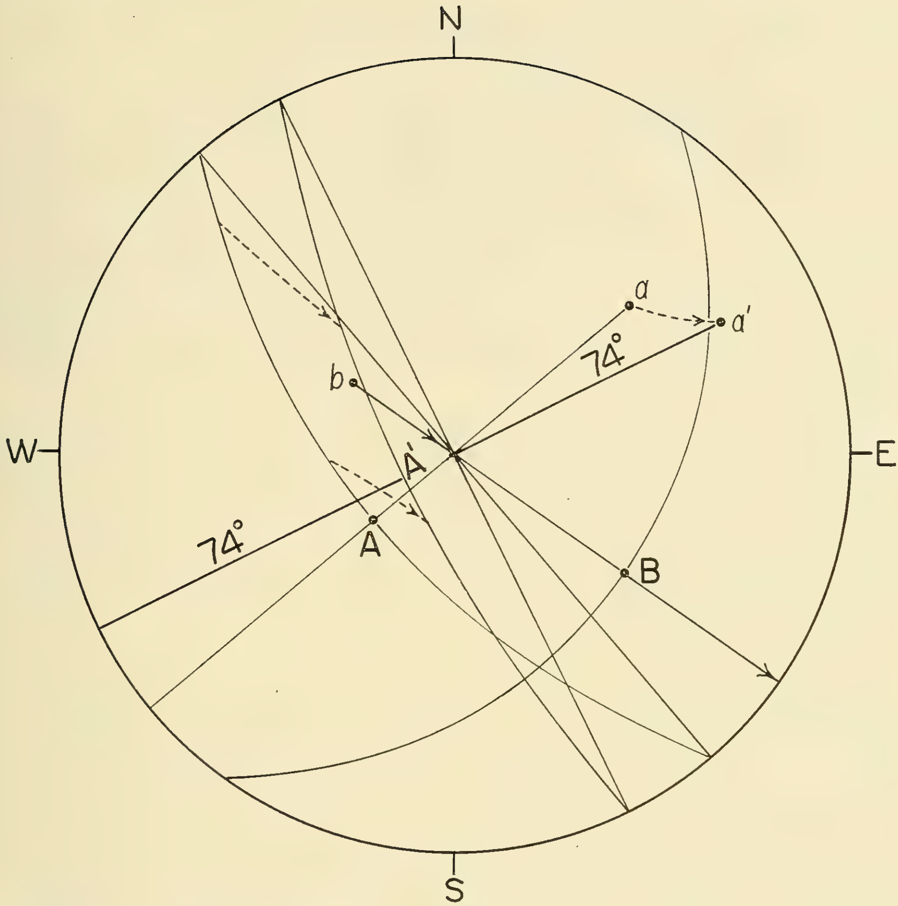


FIGURE 25-6. Stereogram of the problem of two tilts solved by both cyclographic and polar projection.

circles. True dip is then measured on the W-E line as 40 degrees. When the stereogram is oriented to N, the direction of dip is seen to be north 23 degrees west.

The Problem of Two Tilts (3)

We have an angular unconformity, with the lower series of beds, A, dipping 60 degrees on azimuth 230 degrees, while the upper series, B, dips 35 degrees on azimuth 125 degrees. We are required to find the dip and strike of beds in series A during deposition of series B, presumably in a horizontal position. Solution of the problem requires the rotation of the entire system until series B is horizontal, and then the determination of the new position of series

A. On the stereographic net this determination requires rotation of the sphere. (Fisher, 1938; Johnson, 1939; Bucher, 1944; Phillips, 1954)

Figure 25-6 illustrates the solution of the above example by both cyclographic and polar projection. The first method is easier to visualize, but the second requires less construction. The stereogram is first drawn of the bedding planes of A and B. Now the sphere is to be rotated until plane B coincides with the plane of the stereogram. With point B on the W-E line, move it to the right 35 degrees. At the same time all points on curve A will move 35 degrees to the right along the projected small circles or latitudinal arcs of the net. Two convenient points will be suffcient to locate the new position of the great circle, designated A′. The plane represented by A′ indicates that the original dip of the beds of series A before the secondary tilt was 74 degrees on azimuth 244 degrees.

Turning now to polar projection, one may observe that the normals to planes A and B are represented by the points *a* and *b*. With the stereogram oriented to place *b* on the W-E line, the sphere is mentally rotated until *b* is vertical, having moved 35 degrees to the center. At the same time *a* moves 35 degrees in the same direction along the arc of a small circle to position *a′*, representing the normal to the plane A′, which has the attitude found above.

DETERMINATION OF TRUE DIPS IN WELLS

A number of methods have been developed for orienting cores taken from wells and drillholes (Johnson, 1939; McClellan, 1948; Phillips, 1954). Where it is possible to use these methods, a determination of the direction and amount of dip is made. Unless the hole is very nearly vertical (as shown by a survey), it is necessary to apply a correction for the deflection of the hole. With the growth of improved methods of controlling the direction, many wells are now directionally drilled, and the nature of offshore conditions forces deflected holes in that province, so that the correction of dips for well deflection is growing in importance. The stereographic net offers the best method that is accurate for any angle of well deflection. In addition there is a method for orienting any core if the local strike of the beds can be estimated.

Correction for Well Deflection of Dip in Oriented Core (4)

We have a given deflection of the well at the cored point of 55 degrees on azimuth 155 degrees. The measured dip in the core is 20 degrees, found by some method of orientation to be in a direction 259 degrees azimuth. What is the true direction and amount of dip? As pointed out by Johnson (1939) there is a basic similarity between the problem of two tilts and the correction of core

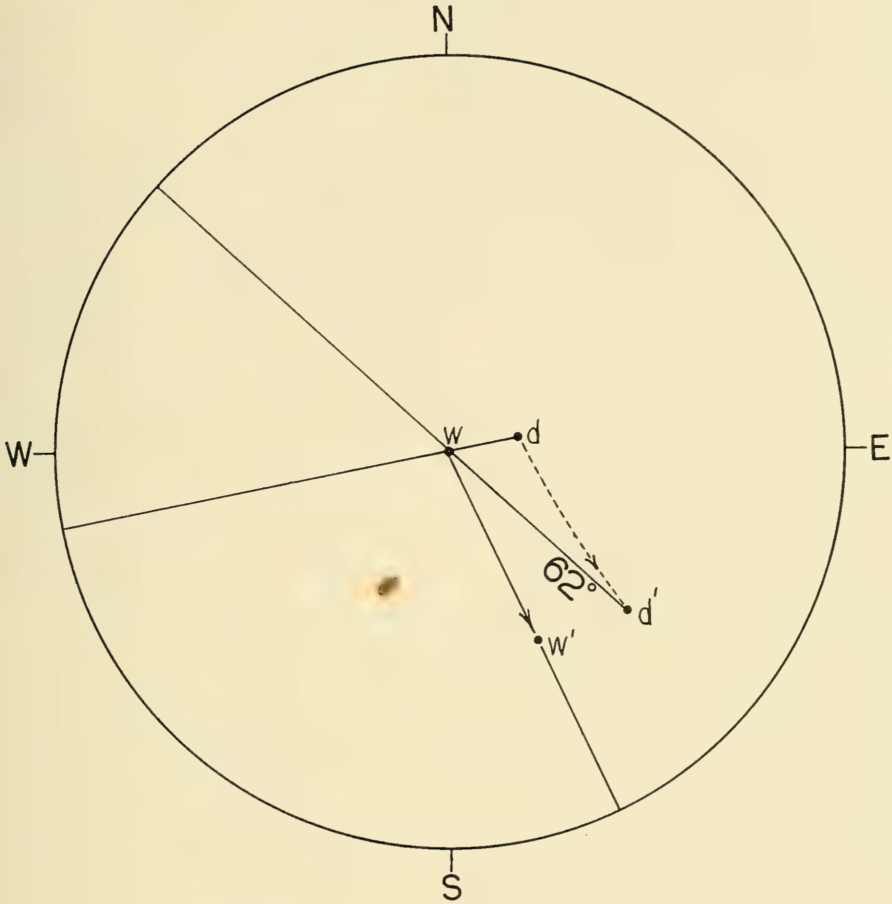


FIGURE 25-7. Correction of core dip for well deflection.

dips for well deflection. In this instance, the hole must be considered vertical when the dip is measured. Then the whole system is tilted until the well is in its true position and the new attitude of the bedding plane determined.

This problem is very simply solved by the use of polar projection and rotation of the sphere. In Figure 25-7 the well is placed at the center of the net in a vertical position. The well may be considered the normal to the core top, now in a horizontal position. The observed dip in the core is measured from the core top. The normal to the bedding plane is represented by *d*, 20 degrees from center in a direction opposite azimuth 259 degrees. When the well is tilted into its true position, azimuth 155 degrees is placed on the E point, and the sphere is rotated 55 degrees. While *w* moves to *w′* position, *d* moves to *d′*,

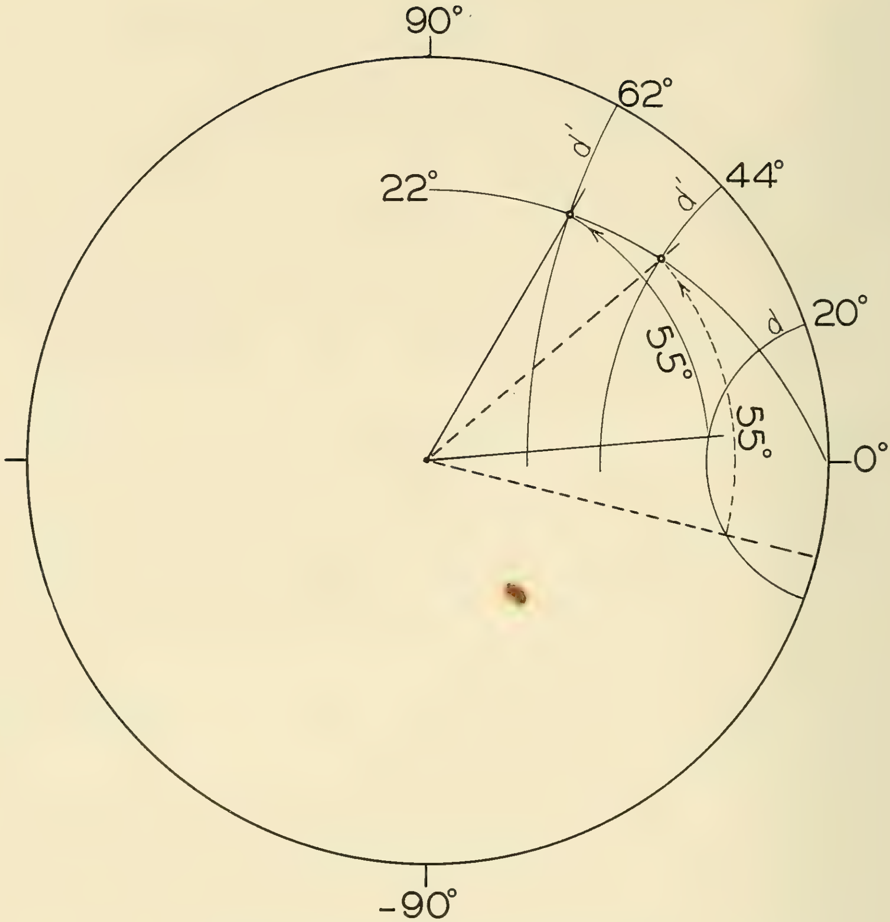


FIGURE 25-8. Orientation of unoriented core.

which is the normal to the bedding plane in its true attitude. True dip is, therefore, 62 degrees on azimuth 313 degrees.

Orientation of Unoriented Core (5)

Unoriented cores present a special problem (McClellan, 1948). It is necessary to estimate the strike of the beds, and unfortunately there are often two possible values of true dip. Selection of the right one will depend on general knowledge of the area. Nevertheless the procedure often gives information of real value. In one instance, where a well was deflected at angles up to 80 degrees from vertical for a distance of more than a mile, most of the determinations had only one answer, which indicated structural conditions far different from those expected. Later dipmeter runs confirmed the work of the stereographic net. When a field is being drilled, the strike is often accurately known; and, if the structure is complicated by faulting and the wells deflected, this method finds frequent use.

The following example will illustrate the method. At the coring point a well is deflected 55 degrees from vertical, in a direction S25E. Therefore the core top is tilted 55 degrees in the opposite direction. The measured dip in the core is 20 degrees. The estimated direction of true dip is N47W. The angle between the direction of tilt of the core top and the estimated direction of true dip is 22 degrees.

For this problem, the stereographic net is turned with N point at the right, 0 degrees on the stereogram (fig. 25-8). The angle 22 degrees is traced on a great circle, measuring from the upper side of the stereogram. The observed dip, 20 degrees, is traced on a small circle, measuring from the 0 point. On a polar stereographic net, the angle of well deflection and tilt of the core top, 55 degrees, is marked off by radii. The stereogram is placed on the polar net, and an arc of a small circle is found that cuts the 22-degree arc and the 20-degree arc exactly 55 degrees apart. By this process we are rotating the horizontal core top into its true position in the well. At the same time the measured dip is rotated *counterclockwise* into its true position. The amount of true dip is found at d', and in this instance, two possible positions for d' satisfy the conditions. If the estimated direction is correct, the true dip, measured by the small circles of the meridional net, may be either 62 degrees or 44 degrees. Other data in the area may indicate which is correct.

If a nonparallel well is available within a reasonable distance, the stereographic procedure for nonparallel drill holes (see p. 546) may be applied for additional information on the most probable strike and dip.

THE DIPMETER

One of the most valuable methods for obtaining true dip in wells is by use of the dipmeter. This special adaptation of electric logging has become particularly useful with the introduction of the continuous dipmeter.

Several articles describe the dipmeter in detail (Chambrier, 1953). It has three electrodes in contact with the wall of the hole at the same level and 120 degrees apart. On passing a tilted bed, the three electrodes will record it at different depths. On the plane determined by these three points, it is a fairly simple matter to calculate the dip. A correction for hole deflection must be made, and usually a correction for magnetic declination.

No doubt a considerable number of geologists and engineers have independently developed methods for dipmeter interpretation. The writer uses a method

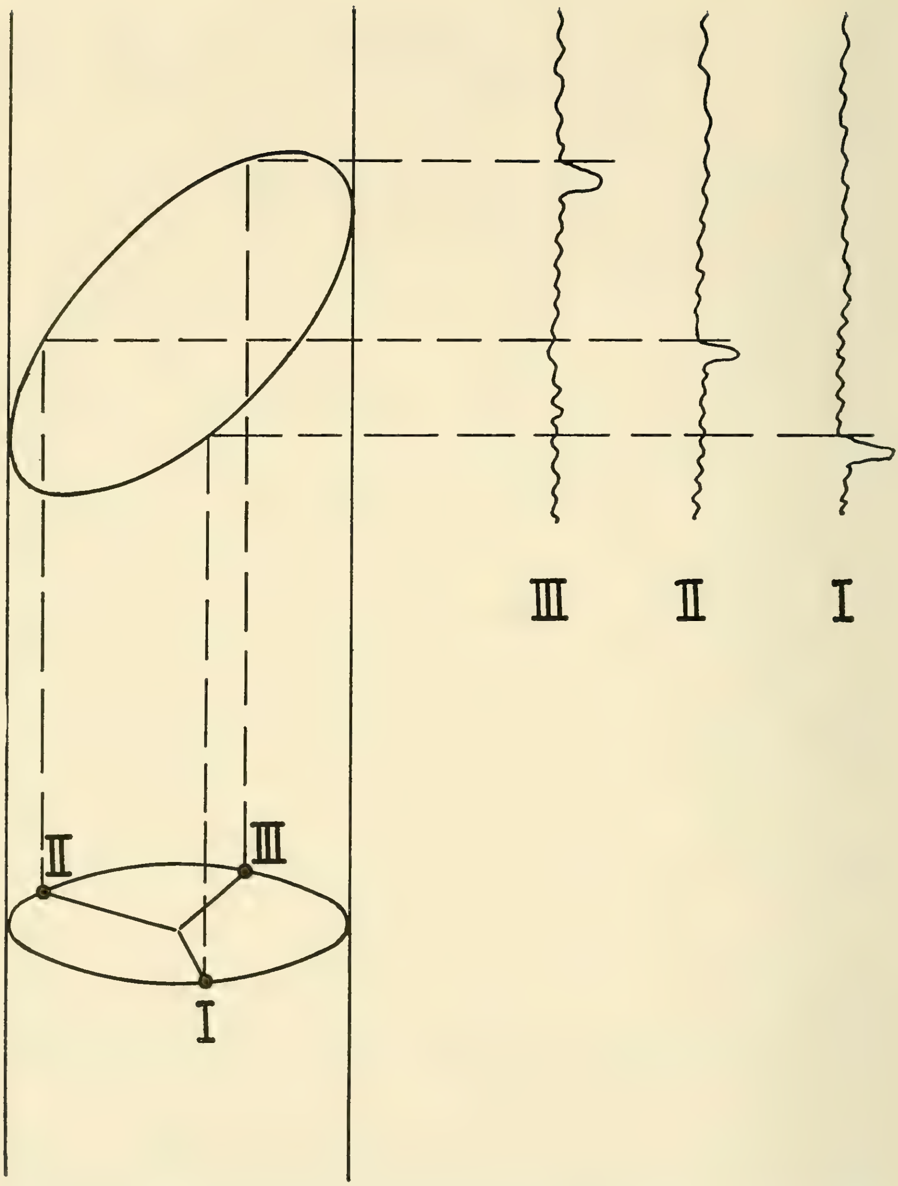


FIGURE 25-9. Diagram of dipmeter device and record of bedding plane crossing borehole (Pierre de Chambrier).

developed with John Cagle in April 1954. Since that time two methods have been published (Prescott, 1955; DeWitte, 1956).

Although the service companies running dipmeter have heretofore made the interpretations, the advent of the continuous dipmeter makes it very desirable for the geologist to do his own calculations. By making a considerable number of determinations, a geologist can localize a fault or unconformity.

Figure 25-9 is a diagrammatic drawing of dipmeter curves. Besides the three formation curves, the continuous dipmeter log carries curves giving the following information: magnetic azimuth of electrode I, the north or south component of well deflection, the east or west component of well deflection, and usually the diameter of the hole. The hole may be quite irregular because of mud cake on porous zones and caving in soft or fractured zones. The hole calipers may fail to reach the wall of the hole in spots, and this may be one source of error.

DIPMETER CALCULATIONS

WELL ______________________ FIELD ______________________

LOCATION ____

			FROM MAGNETIC NORTH														FROM TRUE NO	
DEPTH INTERVAL	HOLE		WELL DIRECTION				WELL DRIFT		AZIMUTH OF ELECTRODES			DISPLACEMENT FR. HIGHEST ELECTRODE			BEDDING PLANE		CORRECTED FOR DRIFT	
	DIAM	RAD.	N	S	E	W	AZIM	ANGLE	I	II	III	I	II	III	DIR.	DIP	DIRECTION	DIP
8050 - 60	10"	5"	6.5°		4.5°		35°	8.5°	234		114°	49° 10"	34°45' 6"	0	266°	49°	282°	54°

Figure 25-10. Form used in making dipmeter calculations.

Interpretation of Dipmeter Records (6)

Figure 25-10 is a convenient form used in making dipmeter calculations. The example shown will be carried through to indicate the methods used. The student will find more detail in the references.

The several companies who run electric logs have different ways of presenting the necessary information. It is advisable to consult the particular company making the run to be sure that all symbols used are understood, and sometimes special scales are furnished to aid in taking the information from the curves.

It will be assumed that the curves made by the three electrodes have been correlated at a particular level and that the information from all curves has been entered on the form. This basic information is underlined in Figure 25-10.

Determination of Well Deflection (7)

On the stereogram (fig. 25-11) the north component of well deflection is measured 6.5 degrees inward from the N point. The east component is 4.5 degrees from E point. Applying procedure 2, one finds that the resultant of the well components is 8.5 degrees on azimuth 35 degrees. It may be noted that the hade of the well is here treated as dip because measurements at the center of the net would not be accurate for these small angles. For well deflections of less than 5 degrees, polar-coordinate graph paper may be used; the angular components of well deflection are plotted as vectors from the center. Although this procedure is not rigorously accurate, the error is too small to be of importance.

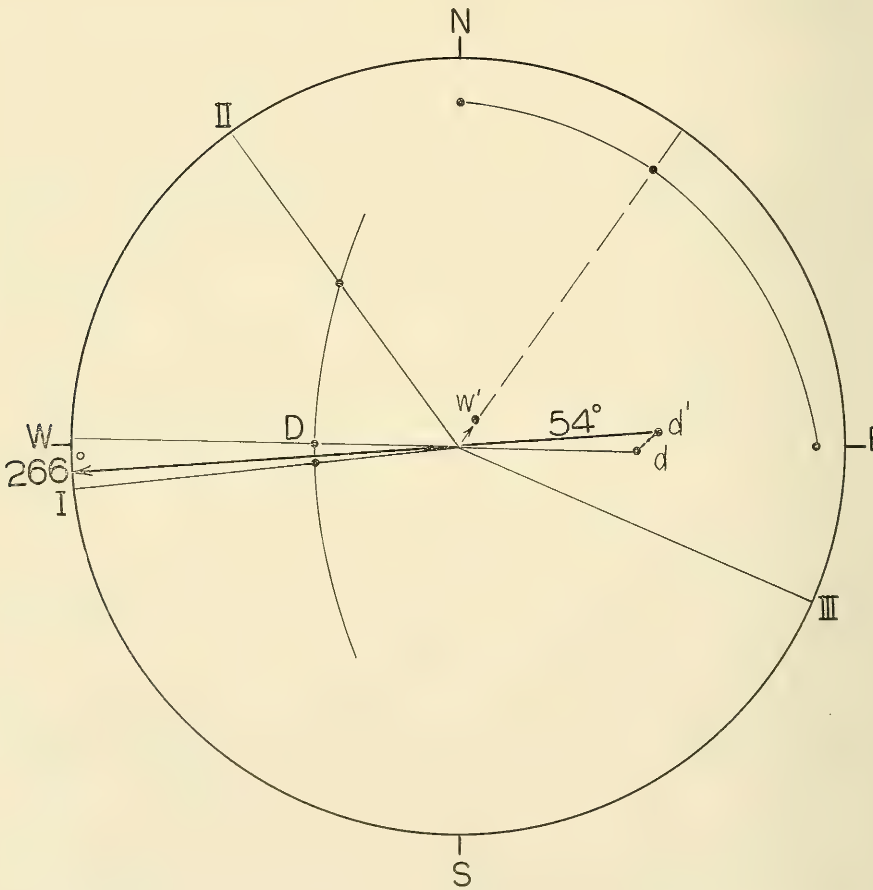


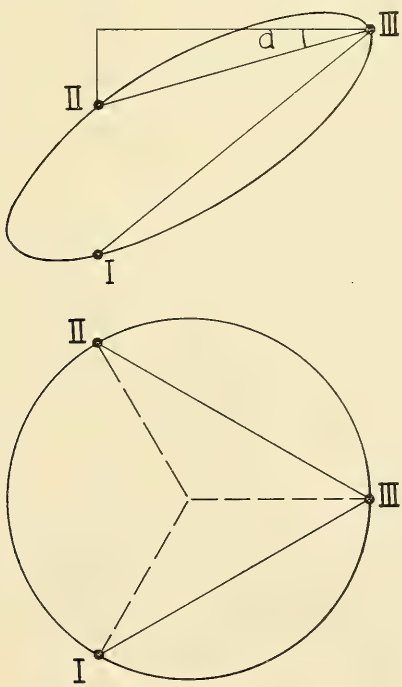
FIGURE 25-11. Example of dipmeter interpretation.

Determination of Bedding Plane (8)

Since dip is measured downward from a horizontal plane, it is convenient to use the electrode reaching the bedding plane at the highest point as the zero electrode, which in this case is electrode III. Electrode I has a recorded azimuth of 234 degrees and the sonde is not spinning; therefore electrode III must be on azimuth 114 degrees. On the curves, electrode I reached the bedding plane 10 inches below III, and elecrode II 6 inches below III. It is necessary to convert these vertical differences to angles within the well bore.

Figure 25-12 illustrates the geometrical basis for the formula: Tan *a* equals depth difference divided by hole radius times 1.732. This may be very conveniently solved by slide rule, but tables eventually may be compiled for this purpose. The angles determined are entered on the form above the depth differences. We now have two apparent dips in the well bore, and the true dip is to be determined.

Placing the stereogram previously begun on the stereo-net, we mark the zero electrode (III) at azimuth 114 degrees, (fig. 25-11). This point is re-



$$\text{Tan. a} = \frac{\text{Depth difference}}{\text{Hole rad.} \times 1.732}$$

FIGURE 25-12. Geometrical relations of dipmeter points on bedding plane in borehole.

volved to the S position and mentally moved to the center. Electrode I will now be 30 degrees to the left of N and II will be 30 degrees to the right. After plotting the apparent dips of I and II, we apply procedure 2, and the true dip D is found to be 49 degrees on azimuth 271 degrees. But these angles must be corrected for well deflection.

Correcting for Well Deflection (9)

The direction of well deflection (az. 35 degrees) has been already marked on the stereogram. To apply procedure 4, the well will be treated as a vertical normal at the center of the net. The normal d to the bedding plane found above is, of course, on azimuth 91 degrees. With the well direction revolved to the E point, the well is tilted into its true position w', and the bedding plane normal d moves 8.5 degrees right on the arc of a small circle to d'. The dip of the bedding plane is now found to be 54 degrees on azimuth 266 degrees. One more correction must be made.

Correcting for Magnetic Declination (10)

In most instances, the dipmeter instruments record all directions with reference to magnetic north. The simplest way to make the correction is to mark the magnetic declination for the locality of the well on the stereographic net, then to revolve the stereogram to place the N point on magnetic north. In this example, the magnetic declination is 16 degrees east. Final corrected dip is therefore 54 degrees on azimuth 282 degrees.

INTERPRETATION OF CORES FROM NON-PARALLEL DRILLHOLES

The use of diamond drilling or core drilling for exploration often presents the problem of interpreting structural information contained in the cores (Fisher, 1941; Bucher, 1943; Gilluly, 1944; Phillips, 1954). In most cases the cores are unoriented. If a key bed can be recognized in three holes not in a straight line the dip and strike can be easily determined. In the absence of key beds, if the local strike of beds can be estimated with reasonable accuracy, stereographic procedure 5, for orientation of unoriented cores, may be used.

If neither of the above methods is applicable, the method of drilling two or more nonparallel holes may be used, and the information obtained combined. Here the number of possible answers resulting may be one, two, three, or four. Selection of the correct one may be made from the probable strike, or perhaps by another carefully located drill hole.

Stereographic Procedure for Nonparallel Drillholes (11)

In Figure 25-13 it is seen that the normal to a bedding plane makes an angle with the axis of the hole equal to the measured dip of the bedding plane.

When the core is rotated to all possible orientations, the normal describes a double cone. As an example, we shall assume that hole A is plunging 45 degrees on azimuth 220 degrees. Measured dip in the core is 30 degrees. Hole B is plunging 60 degrees on azimuth 110 degrees, with measured dip of 40 degrees. The distinction should be kept in mind between plunge of a borehole, measured from the horizontal, and well deflection, measured from the vertical.

The first step in solving the problem is to pass a plane through the axes of the two boreholes. After marking N on the stereogram sheet, we plot the plunges of A and B (fig. 25-14). By procedure 2 the required plane is determined. The sphere is rotated to bring A and B to the position A′ and B′, and now the axes of the two double cones of bedding plane normals will lie

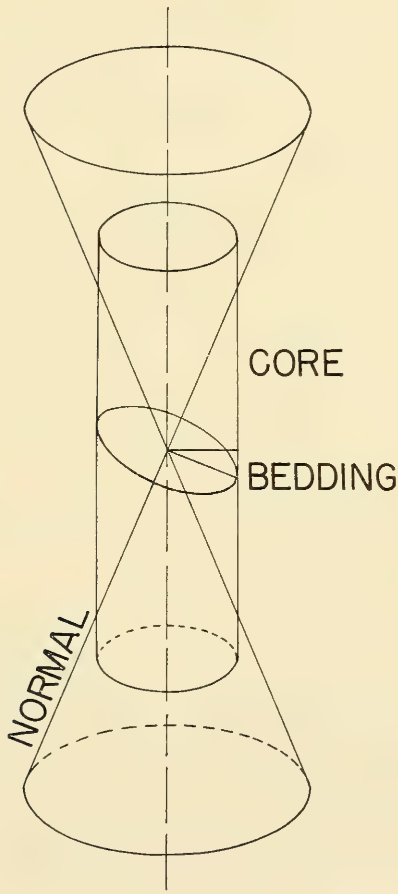


FIGURE 25-13. The double cone of possible positions of bedding plane normals in unoriented core (Phillips).

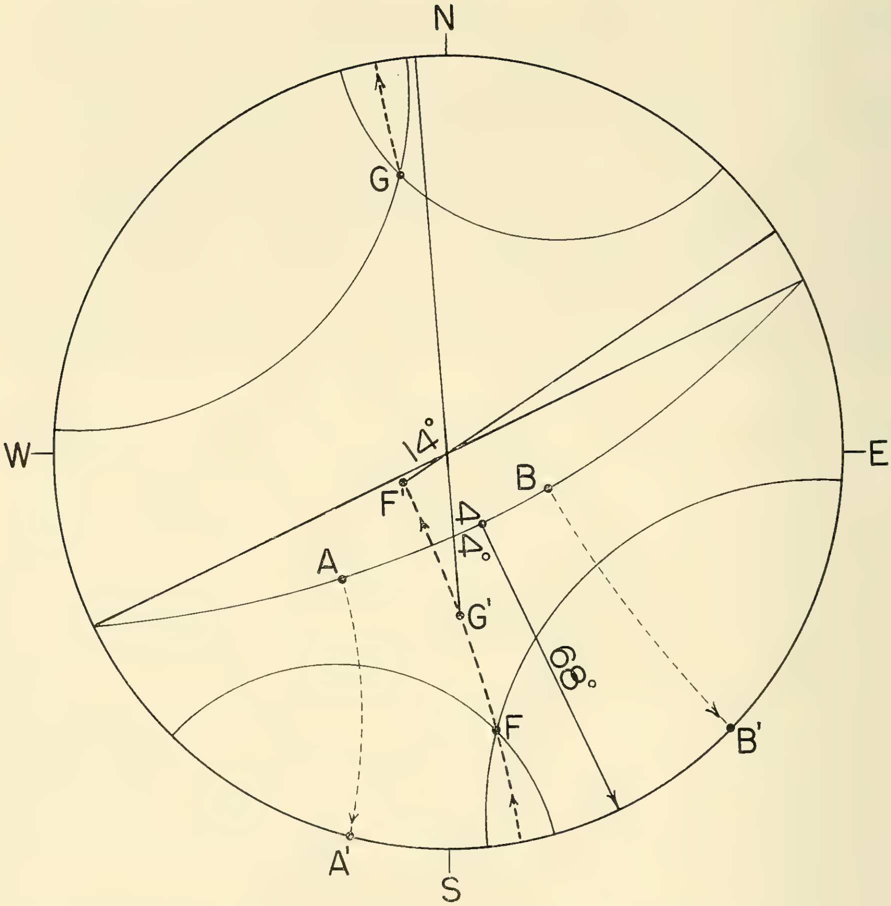


FIGURE 25-14. Stereogram of determination of dip in two non-parallel boreholes.

in the plane of the stereogram. A′ is revolved to the N point, and the projection of the bases of the double cone are traced on the 30-degree small circles. B′ is then oriented to N and the 40-degree arcs traced. It is seen that these arcs cross at points F and G, fixing two possible positions of the bedding plane normal common to both boreholes. To find the true position of these normals, we reverse the rotation carried out with points A and B. F now travels 68 degrees to F′, indicating a dip of 14 degrees on azimuth 56 degrees, while G moves to G′, showing a dip of 44 degrees on azimuth 356 degrees.

Although there are two possible values of true dip in this example, Figure 25-15*a* illustrates the possibility of only one answer, while 25-15*b*, *c*, and *d*

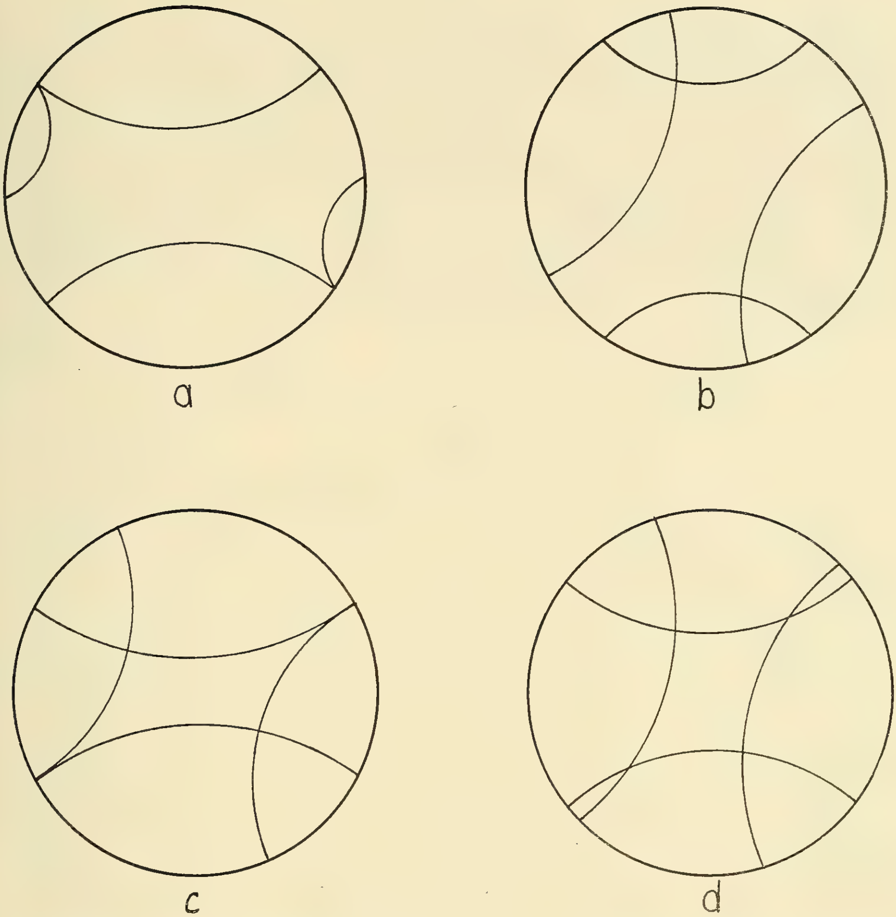


Figure 25-15. Possible intersections of double cones of bedding plane normals in non-parallel boreholes (Phillips).

represent respectively two, three, and four possible answers to the problem of two nonparallel boreholes.

Selection of the correct dip and strike may sometimes be made from general knowledge of the area, but if a third borehole is available, the uncertainty is usually removed. For this procedure refer to Phillips, 1954.

Determination of Correct Dip by Use of Third Nonparallel Drillhole (12)

In the above example, we shall assume a third hole C, plunging 35 degrees on azimuth 160 degrees. The measured dip in the core is 16 degrees.

Hole C is plotted on the stereogram with holes A and B (fig. 25-16). If the bedding plane were perpendicular to the bore hole, the axis of the hole would be the normal. The angle through which this normal must be tilted to coincide with the true normal to the bedding plane should equal the measured dip in hole C. By rotating the stereogram to place C successively on the same great circle with each of the previously determined normals F′ and G′, the angular differences may be measured. In this example, C is 16 degrees from G′, indicating that 44 degrees on azimuth 356 degrees is the correct answer. This may be verified by applying stereographic procedure for nonparallel drillholes to holes C and A, and again to holes C and B.

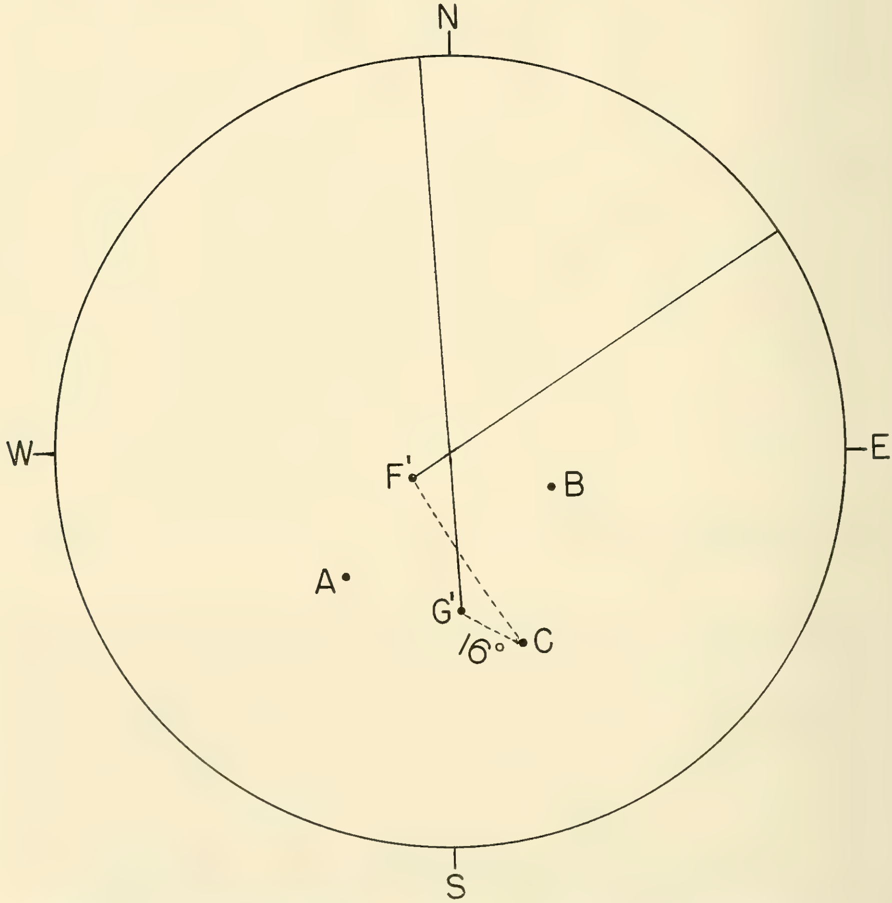


FIGURE 25-16. Use of third borehole to select true strike and dip in non-parallel boreholes.

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Part Five

GEOPHYSICAL AND GEOCHEMICAL PROSPECTING

Chapter 26

SEISMIC PROSPECTING

John C. Hollister
and
W. P. Hasbrouck

The first proposal to obtain subsurface geological information by recording the seismic impulses from an artificial earthquake was made by Robert Mallet to the Royal Irish Academy in 1846 (Weatherby, 1940). In the next two years, he developed a mercury-bowl seismoscope and measured the velocity of artificially produced earth waves through the granites of Dalkey Island. According to DeGolyer (1935), there is little doubt that Mallet discovered the seismic refraction method.

The large explosive charge studies of General H. L. Abbott in 1876, the the falling weight or "thumper" of Milne and Gray in 1885, the theoretical studies of C. G. Knott in 1899 and of Wiechert and Zoeppritz in 1907, and the nine-mechanical-seismograph profile of O. Hecker in 1900 constituted significant steps in the early progress of the seismic methods.

The first use of reflected energy was made in 1914 by Reginald Fessenden while using his Sonic Sounder to find ocean depths. Three years later, W. P. Haseman and J. C. Karcher of the National Bureau of Standards considered the feasibility of using reflected seismic waves in the location of potential oil structures. Preliminary experiments in a rock quarry in Washington, D. C. resulted in the first successful reflection seismogram. In 1921 with D. W. Ohern, Irving Perrine, and W. C. Kite, Haseman and Karcher set out to test the reflection method. After initial failure on what was later to be recoginzed as the

Oklahoma City structure, they successfully defined the flank of a known dome near Dougherty, Oklahoma, on a properly migrated record section.

At about the same time, L. Mintrop of Germany applied for a patent covering a refraction technique for locating the depth and type of subsurface formations. He brought his rather crude instruments to North America and in 1924, working for the Gulf Oil Company, located the Orchard Dome of Bend County, Texas, the first refraction discovery in the United States. In 1927, Amerada's Geophysical Research Corporation under DeGolyer discovered the Maud Pool in Oklahoma. This was the first success of the reflection method.

These were the beginnings of a series of discoveries that established the seismograph as an essential petroleum prospecting tool. Seismic activity increased from 41 crew-months in 1930 (Lyons, 1955) to 11,000 crew-months in 1955 (Patrick, 1957), a gain of some 27,000 percent. Each year several hundred million dollars are spent in seismic exploration.

Because of its comparatively simple field operation and its remarkable depth of penetration, the reflection method almost eclipsed the earlier refraction method in the search for oil. Certain problem areas, however, produced no reflections, and the seismologists resorted to refraction shooting. Today we realize that each method has its place in exploration. Likewise, even the ardent seismologist has come to realize the importance to the exploration picture of the complete integration of all pertinent information regardless of its source.

The common procedure employed in reflection seismic prospecting on land is illustrated in Figure 26-1. It consists of electrically detonating an explosive charge and recording as a function of time the resulting seismic energy as it arrives at a group of vibration detectors or seismometers disposed in a particular array on the surface of the ground.

Portions of the seismic energy thus generated reach the seismometers by several different routes. One portion travels directly to the surface and then spreads out over the ground as a surface wave. Another travels along a subsurface layer and is refracted to the surface. A third travels downward until it reaches an abrupt change in lithology, then reflects back to the surface.

Only energies traveling by refracted and reflected paths are identified on the seismic record or seismogram shown in Figure 26-1. They are respectively first arrival events E and reflected events F. The surface wave has been suppressed in the recording process, thus leaving only background noise as extraneous excursions.

In the recording process, seismic energy reaching each seismometer is transformed into electrical energy, which is amplified and fed to a mirror galvanometer. Light reflected from this mirror traces on moving photosensitive paper a line whose lateral excursions are a function of the ground motion. Each combination of seismometer, amplifier, and galvanometer commonly is known as a channel. A channel may contain a multiplicity of seismometers connected to

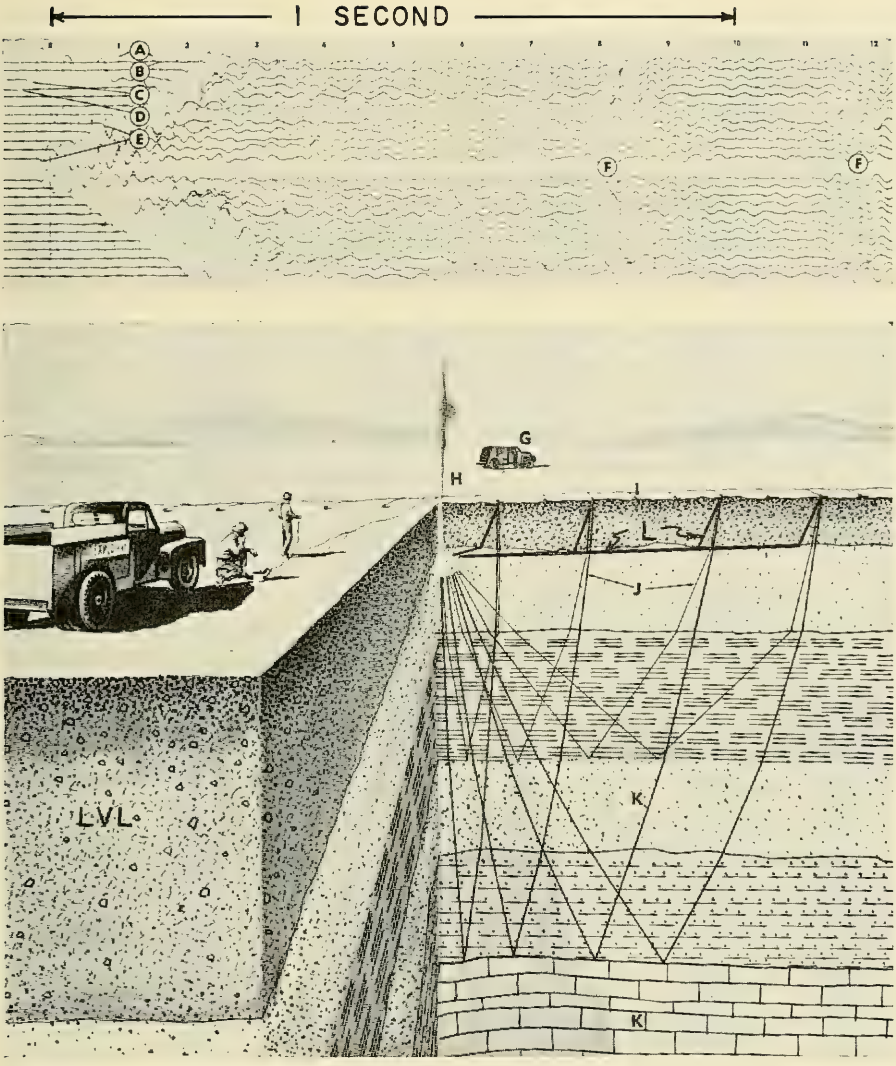


FIGURE 26-1. An actual seismic record (seismogram) and a schematic diagram of the simple subsurface section from which it might have been taken. A — Timing lines recorded at the rate of 100 per second allowing event timing to one millisecond, B — Galvanometer traces representing ground motion, C — Arrival time of energy from shot to the top of the shot hole or uphole time, D — Time of detonation or "time break," E — First arrivals of energy, usually refracted events, F — Reflected events or reflections, G — Recording truck, H — Shot, I — Seismometers, J — Reflected wave paths, K — Reflecting horizons, L — Refracted wave paths, LVL — Low velocity layer. (After "Careers in Exploration Geophysics," Society of Exploration Geophysicists)

feed a single amplifier. In addition to recording information from the 24 to 60 channels which make up a modern reflection seismograph, the seismogram photographs timing lines, the initiation of the shot and the arrival of direct energy at the top of the shot hole, events A, D, and C of Figure 26-1.

The reflection seismic amplifier is complicated by an automatic gain control to hold weak and strong seismic pulses to a similar excursion level on the seismogram, a set of filters to emphasize the frequency range of the desired signals and a crossover network for mixing signals among adjacent channels. The conventional reflection seismograph has a frequency pass band of 20 to 90 cycles per second. Wide range seismographs adapted for magnetic tape recording and later selective play-back may have a 5 to 500 cycles per second response. Such systems are suitable for refraction, conventional reflection and shallow or high-frequency reflection seismic prospecting. The versatility of data display permitted by magnetic recording will be discussed later.

Although chiefly conducted on land, seismic operations are now extensively performed in the exploration of water-covered areas. Boats replace trucks, seismometers or pressure transducers are trailed, and shots are set off in the water.

In land operations, elastic waves, generated near the ground surface, usually by a buried explosive charge but sometimes by falling weights or charges above the ground surface, are broadcast, or in special cases partially beamed, from the vicinity of the source throughout the adjacent region of the earth's crust. Much of the energy from a buried explosive charge or shot is dissipated in fracturing and compacting the material immediately surrounding the shot. Of that energy which survives as an elastic wavelet or pulse, some reaches vibration detectors distributed in the general vicinity. The relative placement of these detectors with respect to the source and the relative arrival-times with respect to the initiation of the shot by whatever path this elastic energy may travel, comprise a set of data from which structural and lithologic information may be gained.

We measure, then, two variables — time and distance — in our effort to determine the location, configuration, and attitude of our subsurface target. We are sometimes guided by two others — relative amplitude and frequency. Because of the multiplicity of recording channels employed, we obtain a corresponding number of simultaneous equations from which to determine the position and attitude of the reflector segment.

In common with some of the electrical prospecting methods, we create the very force field whose reactions we determine, rather than measure those uncontrolled fields inherent in the earth as encountered in magnetic or gravity prospecting. There is a further and unique advantage in seismic prospecting: we can examine and to some degree appraise the significance of the data as they are obtained.

SEISMIC WAVE TRAVEL The elastic wavelets which propagate through the various isotropic regions of the inhomogeneous crustal material are of three types: (1) longitudinal or compressional, (2) transverse or shear, and (3) surface. In general, only the first is useful in subsurface exploration, the transverse and surface waves (when recorded) being relegated to the category of noise. There are exceptions; e.g., depth determinations by composited reflections (Ricker and Lynn, 1950), dynamic soil studies (Heiland, 1939), and the phase velocity method of exploration (Press, 1957).

Both longitudinal and transverse waves are body waves, i.e., propagating within a material body as opposed to traveling along its surface. The longitudinal wave is characterized by particle motion to-and-fro along the direction of propagation. It travels with a velocity, V_L, which depends on Young's modulus, E, density, δ, and Poisson's ratio, σ, for the material, given by the expression

$$V_L = \sqrt{\frac{E}{\delta} \frac{1-\sigma}{(1-2\sigma)(1+\sigma)}}$$

In terms of bulk modulus, K, and modulus of rigidity, μ, the velocity can be written as

$$V_L = \sqrt{\frac{3K+4\mu}{3\delta}}$$

In the transverse plane wave, particles oscillate at right angles to the direction of propagation. The propagation velocity, V_T, of the transverse wave is not dependent upon the compressibility of the material but only on its rigidity and density and

$$V_T = \sqrt{\frac{E}{\delta} \frac{1}{2(1+\sigma)}} = \sqrt{\frac{\mu}{\delta}}$$

Brief comparison of these two velocity expressions leads to the conclusions that the longitudinal velocity of a medium is always greater than its transverse and that fluids, having very low values of rigidity can be considered as failing to support transverse waves. [It has been estimated (Gutenberg, 1951) that the μ of fluids is in the order of 10^{-6} that of steel.]

Among the several factors that control the seismic wave velocity of formations are lithology, depth of burial, structural position, and geologic age. The typical values given in Table 26-I illustrate the effect of some of these factors. We note that in general, the greater the depth of burial or the greater the geologic age, the higher the velocity. In light of the velocity equations, one would think that the increase in density which accompanies greater compaction should decrease rather than increase velocity. Since it is velocity that we observe, we can only conclude that the elastic constants increase to a greater degree than does density. Weatherby and Faust (1935) demonstrated the effect of geologic age upon velocity in a study of data from some 50 well velocity surveys. It has been noted (Athy and McCollum, 1937) that higher velocities are sometimes encountered over structural highs.

Lithology is the most influential factor, and its effect may be attributed largely to mineral composition, porosity, degree of cementation, and the nature

TABLE 26-I

Longitudinal Wave Velocities

After Birch, "Handbook of Physical Constants"

Material	*Depth feet*	*Longitudinal Velocity ft./sec.*
Sand	0	660 - 6600
Alluvium	0	1650 - 6500
Shale and Sandstone		
Pleistocene-Oligocene	2000 - 3000	7200
	3000 - 4000	8100
Eocene	2000 - 3000	9000
	3000 - 4000	10000
Cretaceous	2000 - 3000	9300
	3000 - 4000	10700
Permian	2000 - 3000	10000
Pennsylvanian	2000 - 3000	11200
	3000 - 4000	11700
Devonian	2000 - 3000	13400
	3000 - 4000	13500
Limestone		
Cretaceous	0	11000
	3300	13500
Permian	4000	15500
Pennsylvanian	0	15000
	3000	15500
Mississippian	0	12500
	4800	17000
Devonian	0	14000
	4600	17500
Ordovician	0	16700
	4000	20000
Cambro-Ordovician	0	17400

of interstitial fluid. Clearly, the kind of rock has a dominant effect upon velocity. Igneous rocks, in general, have higher velocities than sedimentary rocks although there are exceptions. Among the sediments, carbonates and evaporites exhibit higher velocities than do sandstones and shales.

The presence of interstitial fluids has a diverse effect upon velocity, which has been studied by many investigators in recent years. Seismic field crews long have observed the increase in velocity produced by water saturation of unconsolidated surface material. Recent continuous velocity logging data (Hicks and Berry, 1956) indicate that the presence of liquids increases the seismic velocity; in fact, for a given rock framework, a separation among gas, oil, and water-filled zones may be made on the basis of comparative velocities. Hicks and Berry (1956) illustrate these relations in the idealized logs shown in Figure 26-2. Contrarily, laboratory data of Hughes and Kelly (1952) and Wyllie, Gregory and Gardner (1956) show that air-saturated cores under high pressures exhibit velocities that are greater than the same cores water-saturated under the same high pressures. These apparent contradictions appear to be dependent upon the pressure range and the relative pressures of the rock framework and the filling fluid. From field experience, it would seem then that introduction of interstitial liquids tends to increase formation velocity within the pressure ranges encountered in prospecting.

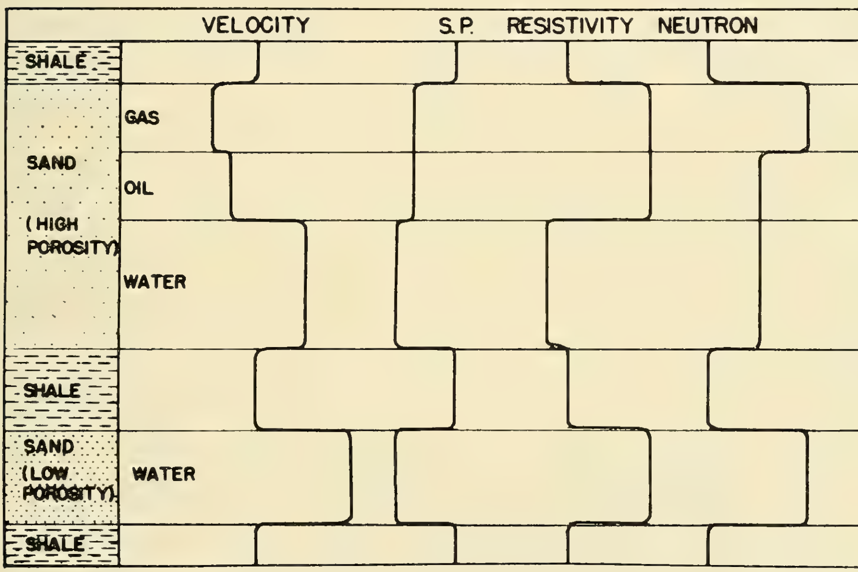


FIGURE 26-2. Idealized logs from Miocene sands and shales. The high-porosity sand exhibits an increased velocity as the filling fluid changes from gas to oil and from oil to water. Also a comparison of the water sands reveals an inverse relationship between wave speed and porosity (Hicks and Berry, 1956).

The seismic energy resulting from a concentrated charge in a spherical cavity in an isotropic homogeneous material radiates as a compressional or longitudinal pulse whether or not the material is absorptive. If, as in earth materials, the medium is absorptive, the higher frequency components contained in the original pulse are attenuated; the pulse breadth increases and its contained energy decreases. The mechanism by which this modification develops has been a matter of study by numerous investigators, notably Sharpe (1942), Ricker (1953), Born (1941), and McDonal, Mills, Sengbush, and White (1955). Agreement among their conclusions is lacking, and we can only state that with very limited exceptions (Pickett, 1955), the longer the path the less the high frequency content.

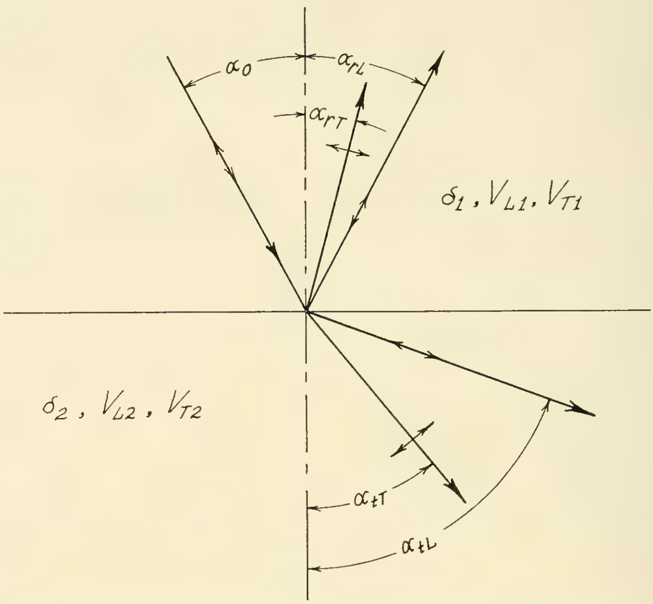


FIGURE 26-3. Four wavelets result from an incident longitudinal plane wavelet impinging upon an interface between media of different elastic constants and densities. The directions of propagation are shown by $\rightarrow$ and the directions of particle displacement by $\leftrightarrow$. The angles relate as $\sin a_0/V_{L_1} = \sin a_r L/V_{L_1} = \sin a_r T/V_{T_1} = \sin a_t L/V_{L_2} = \sin a_t T/V_{T_2}$. V_L and V_T are the longitudinal and transverse velocities respectively and δ is the density. The subscripts L and T represent "longitudinal" and "transverse" respectively; r and t stand for "reflected" and "transmitted."

When in its travel through the layered crust a wavelet encounters an interface between media of different elastic constants and densities, it divides into several parts. When for instance, as in Figure 26-3, a longitudinal plane wavelet reaches a plane interface between such extended media in angularity with its direction of propagation, it splits into four wavelets: two longitudinal and two transverse. One longitudinal and one transverse are reflected and one of each type is transmitted. The angle which the path of each would make with a normal to the interface is related to that of the incident wavelet through Huygen's principle.

Two extreme conditions are characterized by significant phenomena. The first is reached when the angle of incidence is such that the path of the transmitted longitudinal wavelet is parallel to the interface. We speak of the angle in this case as the critical angle. The second extreme is reached when the path of the incident wavelet is normal to the plane interface. Here only two wavelets are formed, one reflected and one transmitted, both of the same type as the parent.

Since we are concerned with longitudinal wavelets in seismic prospecting, let us consider relationships of pulse size and energy intensity which exist among the three waves involved in our second case when only longitudinal wavelets are present. If a plane longitudinal incident wave of amplitude M_o produces a reflected wave of amplitude M_r and a transmitted wave of amplitude M_t, then the amplitude ratios are:

$$\frac{M_r}{M_o} = \frac{\delta_2 V_{L_2} - \delta_1 V_{L_1}}{\delta_2 V_{L_2} + \delta_1 V_{L_1}}$$

and

$$\frac{M_t}{M_o} = \frac{2\delta_1 V_{L_1}}{\delta_2 V_{L_2} + \delta_1 V_{L_1}}$$

The product of density and velocity is commonly called specific acoustic impedance.

The corresponding energy intensities, i.e., energy crossing a unit area in unit time, will be related as

$$\frac{I_r}{I_o} = \left(\frac{M_r}{M_o}\right)^2 = \left(\frac{\delta_2 V_{L_2} - \delta_1 V_{L_1}}{\delta_2 V_{L_2} + \delta_1 V_{L_1}}\right)^2$$

$$\frac{I_t}{I_o} = \frac{\delta_2 V_{L_2}}{\delta_1 V_{L_1}}\left(\frac{M_t}{M_o}\right)^2 = \frac{4\delta_1 V_{L_1}\delta_2 V_{L_2}}{(\delta_2 V_{L_2} + \delta_1 V_{L_1})^2}$$

Looking at the reflected-incident amplitude ratio, we note that differences in density as well as differences in velocity can produce reflections; also, if $\delta_1 V_{L_1} > \delta_2 V_{L_2}$, a reversal of phase results. This phase reversal phenomena is often observed particularly where multiple reflections occur.

The relatively simple reflection phenomena which occur at the boundary between two thick media become extremely complicated when the number of interfaces increase and the thickness of the layers becomes less than the "wavelength" of the seismic pulse. We recognize this complication from acoustic theory. It has been demonstrated vividly by Woods (1956) in a series of graphic results obtained from experiments with a one dimensional model. The model consisted of a 300-foot length of 2-inch pipe, at one end of which were placed a small loudspeaker (electrically pulsed to simulate the shot) and a microphone (the seismometer). Geologic formations were modeled by variations in the cross sectional area of the pipe, using pieces of wood cut to desired shapes and introduced into the pipe. Any desired bed sequence could thus be simulated. The results of some of his work are shown in Figure 26-4. Whereas the model cannot be expected to yield quantitative results, its value is best expressed by Woods, "These records have been used to advance the argument that each reflection seen on a seismic record is nearly always a composite of several reflections. In seismic exploration, a constant source of error is the naive idea that each line-up on the record represents a single interface which is to be plotted on a cross section at a definite depth. There is the companion idea that each line-up on a seismic record is to be correlated with some single sharp kick on the well resistivity log. It is to dispel these ideas that the experiments were made with the acoustic model." Despite the widespread tendency to correlate a particular reflection with the top or bottom of a particular geologic member, we must realize that this may not be the case and temper our belief accordingly.

GEOMETRY OF RAY PATHS A line drawn to represent a particular path along which a wave propagates is called a ray path. In an isotropic medium the ray paths are perpendicular to the wave fronts. In seismic prospecting ray-path geometery is of much importance. The pictures used to illustrate the geometry of ray paths are known as ray-path diagrams (figs. 26-5, 26-6, 26-7, 26-8). The assumption of a constant velocity within each individual layer requires that the ray paths be straight within each layer, and thus simplified computing equations result. In many cases, the use of straight-ray paths is justified because the results obtained through their use fall within the limits of error established for the particular prospect. If the simpler methods prove inadequate, more refined techniques (such as curved-ray methods) are indicated. Standard reference books on geophysical prospecting (Broughton Edge and Laby, 1931; Dix, 1952; Dobrin, 1952; Eve and Keys, 1954; Heiland, 1946; Jakosky, 1950; Nettleton, 1940) develop equations relating distance, time, and velocity as used in most routine seismic prospecting. These equations must be expressed in terms of the observable or derived quantities obtained from the records and particular time-distance plots.

Travel-time (or time-distance) curves are plots of arrival times versus the shotpoint-to-seismometer horizontal distance (figs. 26-5, 26-6). Through analysis of travel-time curves, the geophysicist may recognize the type of the returned

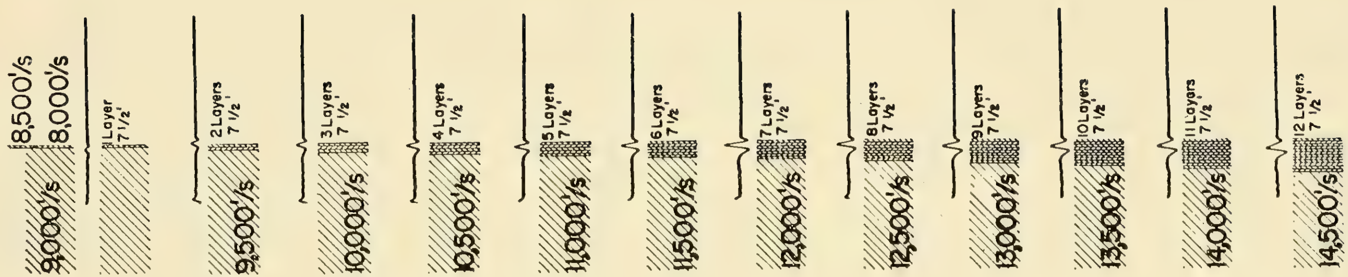


FIGURE 26-4. Some results from a one-dimensional acoustic model. Shown is a sequence of $7\frac{1}{2}$ foot layers bounded by thick beds. Each layer has a prototype velocity 500 feet-per-second greater than the one above. Only a single reflected pulse occurs even when (as at the extreme right) there are 13 interfaces (Woods, 1956).

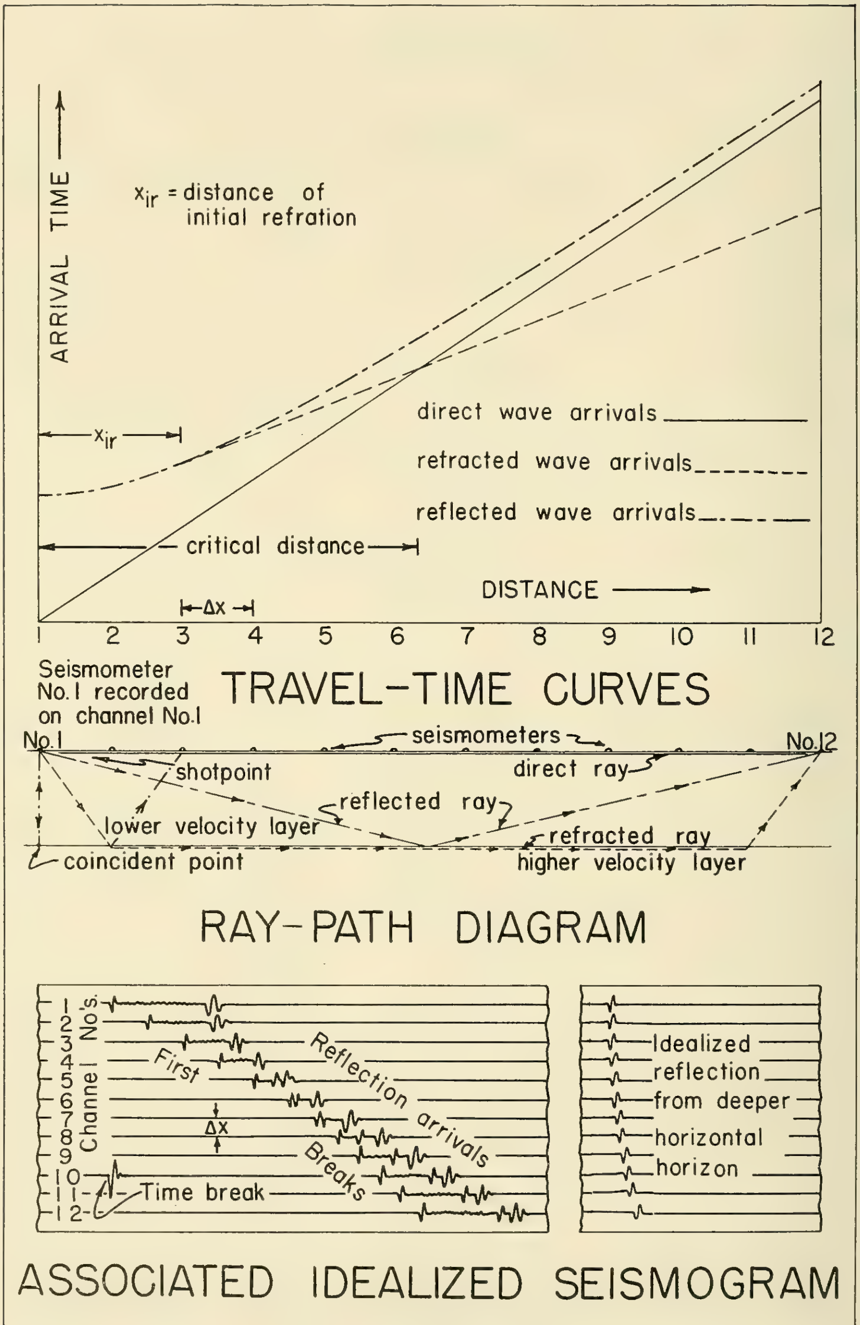

ARRIVAL TIME
x_{ir} = distance of initial refration
x_{ir}
critical distance
Δx
direct wave arrivals
refracted wave arrivals
reflected wave arrivals
DISTANCE
1 2 3 4 5 6 7 8 9 10 11 12
Seismometer No. 1 recorded on channel No. 1
TRAVEL-TIME CURVES
No. 1
seismometers
No. 12
shotpoint
direct ray
reflected ray
lower velocity layer
refracted ray
coincident point
higher velocity layer
RAY-PATH DIAGRAM
Channel No's.
1
2
3
4
5
6
7
8
9
10
11
12
First Breaks
Reflection arrivals
Δx
Time break
Idealized reflection from deeper horizontal horizon
ASSOCIATED IDEALIZED SEISMOGRAM

Figure 26-5

FIGURE 26-5. Relationship among the travel-time curves, the ray-path diagram, and the associated idealized seismogram for the two layer case with no dip between the lower and higher velocity layers. The idealized reflection depicted at a later time on the seismic record illustrates the reflection event from a deeper reflecting horizon of little or no dip.

Several interesting observations can be made from this figure. When the horizontal distance from shotpoint to seismometer is zero, the direct wave arrival time is zero and the reflected wave arrival time would be twice the depth to the interface divided by the average velocity within the layer. The slope of the reflected travel-time curve is zero at $x = 0$ and the slope of the direct wave travel-time curve equals the reciprocal of the velocity in the upper layer. At distances less than x_{ir}, only the direct wave and reflected wave arrivals are present thus to best record reflections from this interface, spreads would be confined within x_{ir}. Note that as the distance outward from the shotpoint increases, the reflection arrival time also increases even though the depth to the interface has remained constant — this time increment constitutes the spread stepout (ΔT_s).

The refracted wave arrival first appears at the distance of initial refraction (x_{ir}), and at this distance the arrival time of the refracted wave and the arrival time of the reflected wave are equal. The direct wave is also present but it has arrived sooner—i.e. at x_{ir} the fastest way to go from shotpoint to receiver is along a direct path. At x_{ir} the slopes of the refracted and reflected travel-time curves are the same and equal to the reciprocal of the velocity of the higher speed (lower) layer.

Both the direct and refracted waves arrive simultaneously when the seismometer is positioned at the critical distance (x_c). Within x_c the first arrivals (often called first breaks) are from a direct wave — outward from x_c the first breaks are from a refracted wave; thus for most refraction prospecting the seismometers would be spread at a distance greater than x_c so that undisturbed arrival times may be used for substitution into the computing equations of the refraction method.

As the distance increases beyond x_c the distance-depth ratio becomes larger and thus the reflection travel-time curve approaches (becomes asymptotic to) the direct travel-time curve. No indications are given on the travel-time curves relative to energy content as such; neither are there depicted in this figure any of the bothersome multiple arrivals (waves which have bounced about within the upper layer prior to being recorded) nor are there shown any of other wave types, e.g. surface waves, which would be present.

This ray-path diagram shows only a few of the rays present yet a sufficient number are presented such that the significant geometric relationships are demonstrated. Both the direct and reflected waves travel wholly within the upper layer, whereas the refracted wave travels from the shotpoint down through the upper layer to the higher velocity layer then along it and finally up through the lower velocity layer to the seismometer. If the velocities of the layers are known, then measurements to a given scale can be made along the applicable paths to give the arrival times — thus a theoretical travel-time curve could be constructed from a ray-path diagram.

Since each channel records the arrival times at different distances from the shotpoint, a multitrace record is in essence a travel-time curve; and as such, the record itself can often be used directly to supply the needed travel-time information.

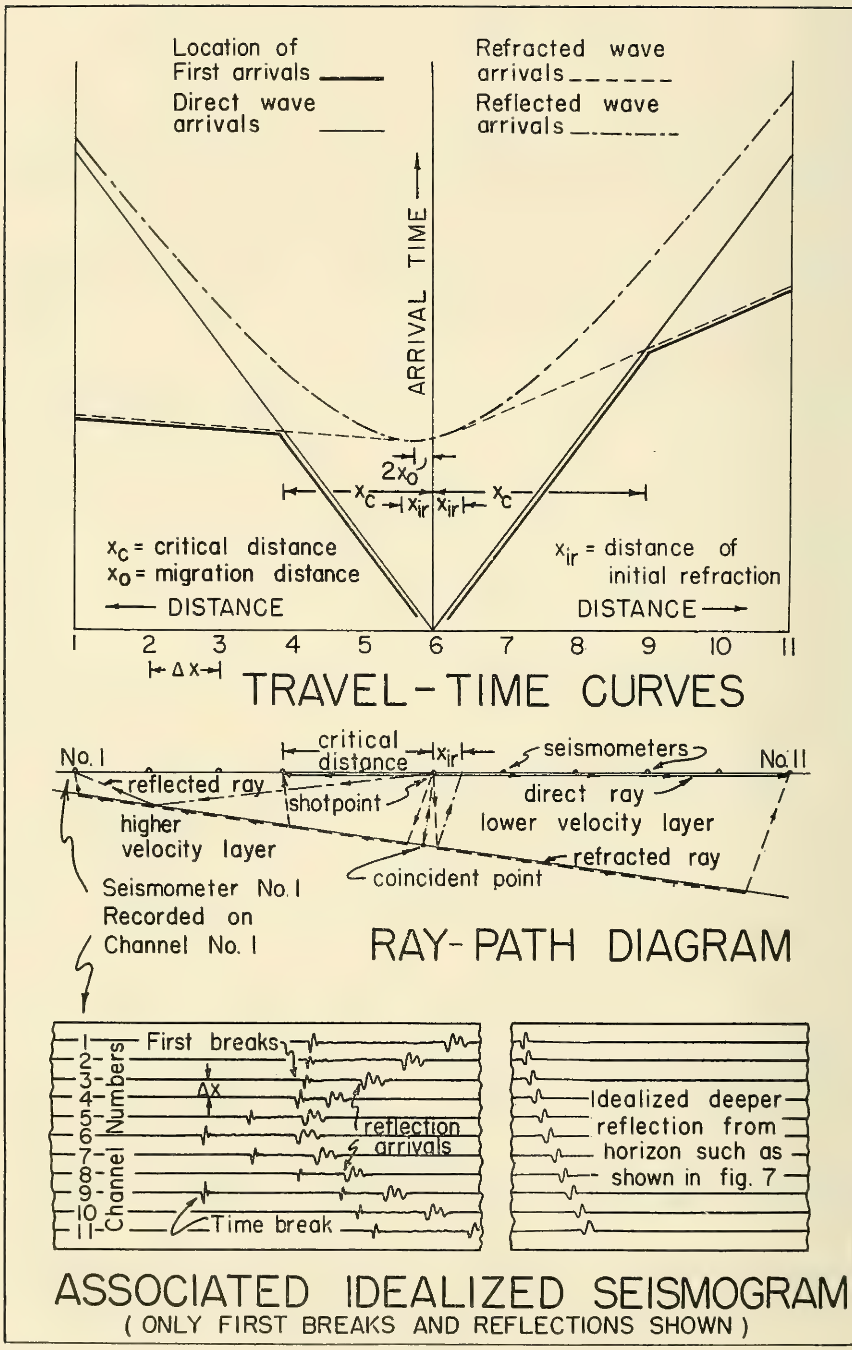

Location of First arrivals
Direct wave arrivals
Refracted wave arrivals
Reflected wave arrivals
ARRIVAL TIME
2x_o
x_c
x_ir
x_ir
x_c
x_c = critical distance
x_o = migration distance
x_ir = distance of initial refraction
DISTANCE
DISTANCE
1 2 3 4 5 6 7 8 9 10 11
Δx
TRAVEL-TIME CURVES
No. 1
critical distance
x_ir
seismometers
No. 11
reflected ray
shotpoint
direct ray
lower velocity layer
higher velocity layer
refracted ray
coincident point
Seismometer No. 1 Recorded on Channel No. 1
RAY-PATH DIAGRAM
1 2 3 4 5 6 7 8 9 10 11
Channel Numbers
First breaks
Δx
reflection arrivals
Time break
Idealized deeper reflection from horizon such as shown in fig. 7
ASSOCIATED IDEALIZED SEISMOGRAM
(ONLY FIRST BREAKS AND REFLECTIONS SHOWN)

Figure 26-6

wave, e.g., direct, refracted, or reflected longitudinal; he gets information concerning velocities; he recognizes the preferred computation procedure (curved-ray techniques may be required in the reduction to datum) and he is aided in the selection of spread distances suitable to accomplish particular objectives.

A close relationship exists among the travel-time curves, the ray-path diagram, and the seismic record. Data for travel-time curves are obtained from properly labeled records, and these curves in turn help to determine the nature of the ray-path diagrams. The equations required to resolve the problems presented are then selected, record data are imposed, and computation proceeds.

In the selection of spread distances to be used in prospecting, the travel-time curves can be of much value. Referring to Figure 26-5, we see that if a refraction technique is to be used to determine the depth, then seismometers must be deployed beyond the critical distance so that undisturbed arrival times (first breaks) will be from a refracted ray; naturally, refraction equations cannot apply except to refraction data. If a reflection method is employed, then the seismometers would be located with the x_{ir} distance so that refractions would not mask the wanted reflection arrivals. Although the direct wave arrival is present, it may attenuate before the reflections are recorded.

As the shotpoint-seismometer separation increases, the reflection time increases even though the depth to the interface is constant. Time differences on records observed between two traces or channels are termed either stepouts or moveouts. If the stepout is due to spread, it would then be termed spread stepout. In the no-dip case, spread stepout is often called normal moveout. The difference between reflection arrival times which exists solely because of the effect of dip is called the dip stepout time. Irregularities in the immediate subsurface can also cause time differences (to be discussed later), and these time differences are known as datum stepouts. Generally speaking, in a constant velocity section, the total time difference between any two traces (called the total stepout time) equals the summation of spread stepout, datum stepout, and

FIGURE 26-6. Relationship among the travel-time curves, the ray-path diagram, and the associated idealized seismogram for the two layer case with a dipping interface between the lower and higher velocity layers. The idealized reflection depicted at a later time on the record illustrates the return from a deeper dipping reflecting horizon such as shown in Figure 26-7. The seismometers are deployed on a line which parallels the dip of the horizons.

If the interface is not dipping, symmetry of travel-time curves exists about the arrival-time axis (see fig. 26-5), but in the dipping case only the direct wave travel-time curves are symmetrical to this axis. The least reflection time would be observed if a seismometer were positioned at $2x_0$, and the slopes of the refraction travel-time curves are different on each side of the shotpoint. The inverse slope of the refraction arrival time vs. distance curve would be equal to the velocity of the higher velocity layer only if the spreads were parallel to the strike of the dipping interface; with other orientations the reciprocal slope leads to an apparent velocity.

dip stepout. In Figure 26-5 the total stepout is due to spread, whereas in Figure 26-6 it is a combination of dip and spread effects.

One of the purposes of seismic calculations is to derive from the total stepout the specific stepouts required — for example, in dip computation, one would be concerned chiefly with the dip stepout; whereas in some procedures designed to find average velocity, the spread stepout becomes of primary importance.

Consider now the reflection travel-time curve for the simplified two layer case with a dipping interface in which the seismometers are spread on lines normal to the strike (fig. 26-6). Ray-path geometry readily shows the position of the subsurface coverage for the spreads chosen. The coincident point is the point on the reflecting horizon where the ray which has traveled down and back on itself has been reflected. If the interface were horizontal and a detector were positioned at the shotpoint, then the coincident point would be located vertically below the shotpoint; likewise if the interface were dipping, the coincident point would be offset or migrated from its zero dip position. Thus in dip work, it is

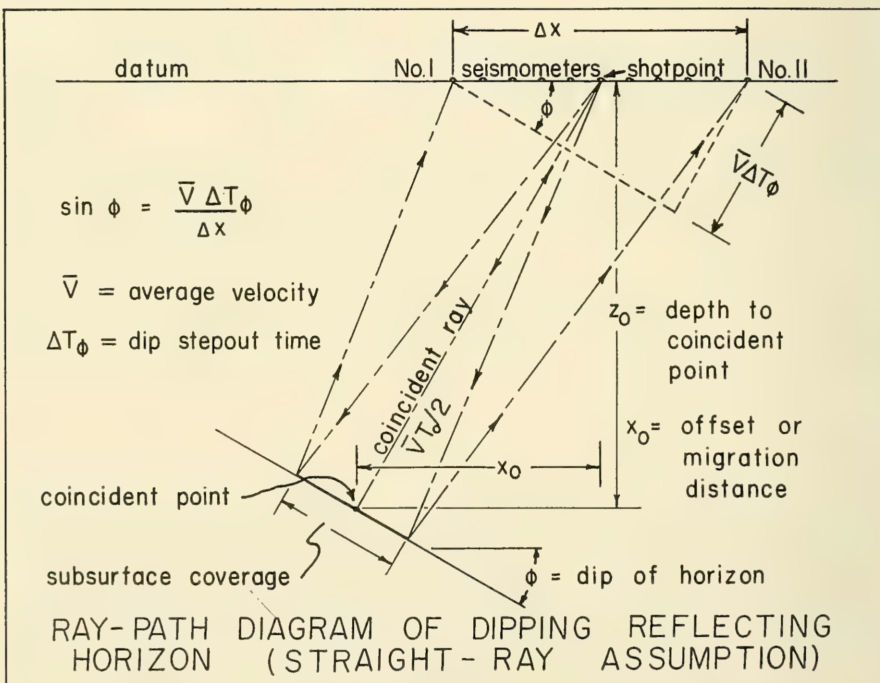


FIGURE 26-7. Straight-ray ray-path diagram of a dipping reflecting horizon. If the seismometers are deployed on a line normal to the strike of the reflecting horizon and if it is assumed that the reflections return as a plane wave, then the dip of the horizon may be computed from the equation $\sin \phi = \bar{V}\Delta T\phi/\Delta x$.

necessary not only to compute the depth to the interface but also to give the lateral location of the reflection points. Even though in this split spread the distances to the Nos. 1 and 11 seismometers are equal, a time difference is shown on the record. This time difference is related to the dip of the interface—the greater the dip, the greater the dip stepout time, and consequently the greater the migration distance.

If the depth of the reflector is large compared to the spread length, then the assumption of an emergent plane wave is often used. Figure 26-7 represents the relations for the dipping case to a somewhat more realistic scale. Under the assumption of an emergent plane wave, the dip angle ϕ is related to the dip stepout, $\Delta T\phi$, to the spread length, Δx, and to the average velocity, $\overline{V}$, by the expression $\sin \phi = \overline{V}\Delta T\phi/\Delta x$.

Reflected travel paths may undergo substantial refraction. Figure 26-8 illustrates refracted-reflected ray paths. In this idealized figure, the ray-path geometry clearly shows that distorted results would be anticipated from under-

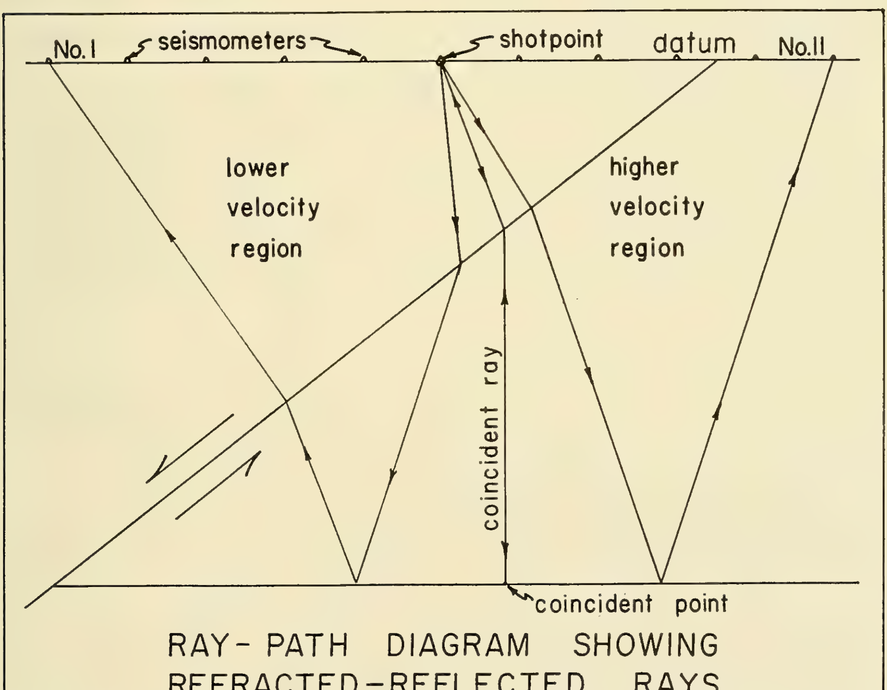


FIGURE 26-8. Ray-path diagram to illustrate refracted-reflected rays. Even though the reflection horizon is horizontal and the shotpoint-seismometer distances are equal, the arrival times at seismometers 1 and 11 would not be the same; thus a false dip and incorrect coincident point would probably be plotted. Although the figure is idealized, nevertheless it indicates that anomalous results are not unexpected in faulted areas.

neath a fault complex. In this particular case, even though a balanced split spread were used, the stepout between seismometers Nos. 1 and 11 would not be zero, and hence a false dip and an incorrect coincident point location would be plotted. Quarles (1950) shows results of seismic surveys in areas of faulting wherein this effect is well demonstrated.

Thus wave-path geometry serves as a foundation for development of computing equations, as an aid in spread selection, and as a basis for interpreting perplexing problems which might arise. It is estimated that over 50 million sketches of ray-path diagrams have been made by geophysicists all over the world.

COMPUTATION PRINCIPLES

No computation procedure can be expected to yield results which will exactly answer the highly complex problems presented by the earth. What the geophysicist must do, then, is to develop and use computation techniques which, though approximations to the unattainable ultimate, still serve to evolve a subsurface picture of reasonable accuracy and with economy of computation time.

For computation purposes, the subsurface is roughly divided into two zones—the immediate subsurface and the deeper subsurface. Directly beneath the ground surface is a highly irregular zone of low velocity material called the low velocity layer (LVL in fig. 26-1). Rapid variations in the immediate subsurface not related to deeper subsurface structures could either mask the deep structures or build false structures. For example, if a line of shotpoints is shot across an area wherein the LVL decreases in thickness toward the center, then the uncorrected seismograms would indicate a seismic high in the central region. Thus since the principal objective of seismic prospecting is to find traps favorable for the accumulation of oil, the effect of the irregular immediate subsurface must be removed by computation. This procedure usually is termed reduction to datum. It is generally assumed that beneath the datum an overall regularity of velocity distribution exists.

We generally recognize 3 classes of datum surfaces: regional, floating, and fixed. The regional datum is based on a regional conformity to the isovelocity surfaces. It is perhaps the most accurate of the datum surfaces listed, but it cannot be described until much velocity information has been gained in an area either through surface shooting for velocity or from velocity surveys in wells. A floating datum is one whose elevation parallels the ground elevations and it is presumed that the isovelocity surfaces parallel the ground surfaces. A fixed datum is a reference surface whose elevation is constant.

In datum reduction, the shotpoint and the seismometers are mathematically transferred or "reduced" to datum. Two of the basic procedures employed in the reduction to datum are the uphole method and the refraction method. The uphole method is used when the shothole-seismometer distance is short enough to warrant the assumption that shothole conditions are duplicated under the seismometer, and the shot is below the LVL. Otherwise, a refraction technique is indicated. Occasionally the immediate subsurface is so complex that the usual methods of reduction to datum yield unacceptable results. In such areas, the interpreter may resort to an isochron (often colloquially called an isopach) technique wherein reflection times to deep horizons are compared with those of a selected shallow reflector. This shallow horizon is essentially a datum.

Once the irregular immediate subsurface variations have been removed by reducing reflection times to datum, computation of depth, dip, and offset can proceed. Reference to Figure 26-7 will demonstrate the interdependence of these three quantities, and it becomes apparent that each must be known before the position of the reflector segment can be established. Actually depth and offset are obtained from the coincident wave path $(\bar{V}T_0/2)$ and the dip $(\sin^{-1} \bar{V}\Delta T\phi/\Delta x)$ and all will be well if the seismometer profile lies along dip azimuth. If this is not the case, then $\sin^{-1} \bar{V}\Delta T\phi/\Delta x$ represents only an apparent dip, and it is necessary to shoot in two directions (usually an x-spread), each yielding apparent dips from which both value and direction of true dip are computed by a method similar to that used by the surface geologist for the same purpose.

The conversion of reflection times to depths and stepout times to dips demands a knowledge of velocity distribution both vertically and horizontally, and we must recognize that time presentations so often used in preliminary phases of a seismic survey are in truth depth representations involving an unspecified velocity.

VELOCITY DISTRIBUTION

In the discussion of the geometry of wave paths, we have tacitly assumed that the velocity has remained constant to a particular reflecting horizon. This we know is not true. Each uniform stratum in a layered medium makes its unique contribution to the average velocity through the medium. A many layered section would have such a complex velocity distribution that even though it were known it would be useless as such to the interpreter. He would be obligated to simplify the distribution in order to apply it economically to his needs.

The earliest simplification was the concept that an average velocity prevails to a given depth or to a particular reflector. In essence, this is the same as the assumption of constant velocity. It implies straight ray paths with the resulting simplified geometry. The integration of the contributions of a multitude of layers inherent in the average velocity concept makes its use practical in most areas of low to moderate dip. Migration of reflecting points to their spacial position using straight wave paths and the dip angle expression, $\sin\phi = \bar{V}\Delta T/\phi\Delta x$, usually leads to a reasonable structural picture.

In areas of significant dip, more complicated velocity distributions have been postulated (for a summary, see Kaufman, 1953), two of which predominate. All presume an increase of velocity with depth within a medium of parallel iso-velocity surfaces and imply curved travel paths whose emergent angles are defined by the expression $\sin \propto = V_0\Delta T\phi/\Delta x$. (fig. 26-9).

The most widely used of these velocity functions is one requiring a linear increase of the intantaneous velocity, V, with depth, z, or $V = V_o + kz$, wherein V_o is the initial or datum velocity and k is the velocity gradient. Expressed in verticle time, τ, instead of depth, this function becomes $V = V_0e^{k\tau}$ and is hence

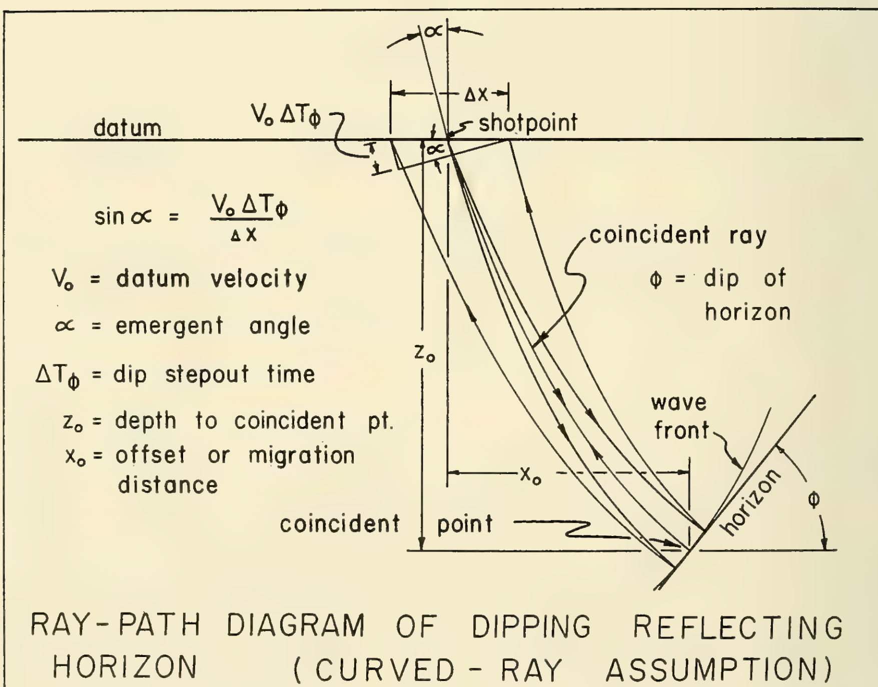


FIGURE 26-9. Curved-ray ray-path diagram of a dipping reflecting horizon. If the seismometers are deployed on a line normal to the strike of the reflecting horizon and if the emergent wave front is taken to be plane, then the emergent angle ($\propto$) can be obtained from the equation $\sin \propto = V_0\Delta T\phi/\Delta x$. Note that with curved-ray paths the angle of emergence and angle of dip of the horizon are not the same. Knowledge of the velocity distribution must be gained before the coincident point can be located and before the relationship of ϕ to $\propto$ can be ascertained.

often called exponential-with-time. Both the resulting ray paths and wave fronts are circular.

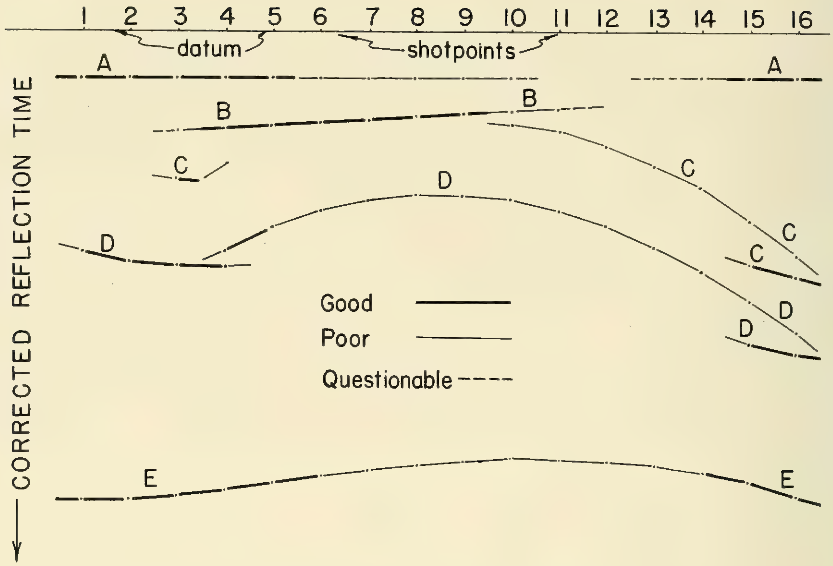
Used to a lesser extent than the linear-with-depth function is a linear-with-time velocity distribution, $V = V_0 + a\tau$, in which a is an acceleration constant. Since in terms of depth this function becomes $V = \sqrt{V_0^2 + 2az}$, it is also known as parabolic-with-depth. The resulting travel paths are cycloidial while the wave fronts are anonymous ovals.

The popularity of the linear-with-depth velocity function over the last 20 years stems from the relative ease of wave-front chart construction once the constants, V_0 and k, have been established. The determination of these constants is somewhat involved (Legge and Rupnik, 1943). In contrast, the constants of the linear-with-time are easy to find whereas chart preparation is laborious. Specialized analog computers have been built to relieve this tedious chore (Musgrave, 1952). Digital computers have so reduced the hours of calculations that wave-front charts may be produced for every few shotpoints in areas of rapid lateral variation of velocity.

Velocity distribution data are obtained by several techniques. The method of long-reflection profiles was the first to be employed and is still very useful in undrilled regions or in areas requiring close lateral control of velocity. When shot across a common centerpoint and along dip azimuth, a long reflection profile yields data which relate to average velocity as $\overline{V} = \sqrt{d(x^2)/d(T^2)} \cos \phi$ where $d(x^2)/d(T^2)$ is the inverse slope of a T^2 versus x^2 plot. In areas where no special effort has been made to secure velocity information, a statistical treatment of data available from a suite of ordinary reflection records results in velocities which are averaged over the prospect.

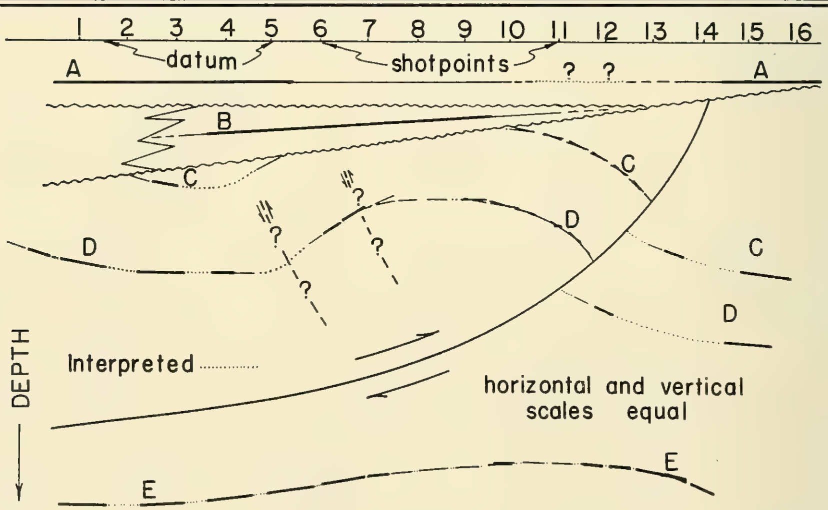
Two other methods of velocity measurement are in current use, both of which require a deep well bore. The first, called well-velocity shooting, has been employed for many years. It consists of lowering a special seismometer into the bore hole, stopping it at numerous depths and shooting at the surface. Time-depth data are thus obtained from which the general velocity distribution is determined and a velocity function may be calculated. Well-velocity shooting is a combined effort involving a seismograph crew to shoot and take the records and a well-logging crew to lower the seismometer into the bore hole.

A few years ago, equipment was designed to make a continuous-velocity log of the formation penetrated by the bore hole (Summers and Broding, 1952; Vogel, 1952). A typical subsurface tool comprises an elastic pulse transmitter separated from a pulse receiver by an acoustic insulator. As the transmitter emits a pulse into the bore hole wall, it simultaneously transmits a time break up the logging cable. When an elastic pulse reaches the receiver, another signal is sent up the logging cable whose arrival time is compared with the corresponding time break. This sequence of events is repeated perhaps 20 times per second. Since the distance separating the transmitter and receiver is fixed, the velocity



UNMIGRATED TIME SECTION
FROM SELECTED REFLECTIONS

FIGURE 26-10A.



SIMPLIFIED INTERPRETED DEPTH
SECTION FROM MIGRATED SEISMIC DATA

(Line of shotpoints parallel to regional dip)

FIGURE 26-10B.

of the formation interval adjacent to the tool is inversely proportional to the time of travel corrected for the time consumed in the well bore. The purpose of the acoustic insulator is to eliminate pulse travel through the tool itself.

The rather complicated surface equipment of a velocity or acoustic logger produces a continuous depth record of formation velocity over the transmitter-receiver separation interval (say 5 feet) and also a continuous integrated time curve representing travel time to the surface. This second curve is comparable to the time-depth plot derived from a conventional well velocity survey.

PRESENTATION OF RESULTS

Having assembled all available seismic information, it behooves the interpreter to display his results in lucid fashion. Two general forms of presentation are prevalent: the cross section and the subsurface map.

The cross section may have as its vertical dimension either time or depth; for depth sections a suitable velocity function must be imposed to convert time to distance. Significant events are transferred from the records to the section where they are represented by appropriate symbols. If the symbols are plotted vertically below the seismometer spread, an unmigrated section such as shown in Figure 26-10A results. Often in areas of steeper dip, a migrated section (idealized in fig. 26-10B) forms a more probable representation. Construction of a migrated section is facilitated by use of wave-front charts (fig. 26-11) or dip plotters. If the symbols appear to form a more or less continuous line as illustrated in Figure 26-10, they may be presumed to represent a continuous reflecting horizon. A break in the continuity of symbol alignment may indicate zones of structural displacement or stratigraphic variation, although it should be borne in mind that a loss of reflections does not always imply a loss of bedding. Only the recorded events which appear significant to the interpreter reach the manually-plotted section and much detail is necessarily omitted.

FIGURE 26-10. Comparison of a highly idealized unmigrated time section (fig. 26-10*A*) and a migrated depth section (fig. 26-10*B*) as constructed from selected seismic events. It has been assumed that the line of shotpoints parallels the general dip in the area. The value of the migrated section is well illustrated by events C and D as recorded at shotpoints 15 and 16. Reflections from both the upthrown and downthrown segments of the C and D horizons appear on the same records, thus when these data are plotted on the unmigrated time section a geologically improbable condition apparently obtains — such is not the case when these same data are properly migrated. Horizon D as depicted under shotpoints 3 and 4 on the unmigrated section appears to be faulted, but on the migrated section the position of these horizon segments is such as might be anticipated with tighter folding. Fragments of horizon C (as recorded from shotpoints 3 and 4) when properly migrated aid in the better location of the unconformity. In areas of relatively small relief (as indicated by horizons A, B, and E), the unmigrated section is sufficient to indicate regions of interest.

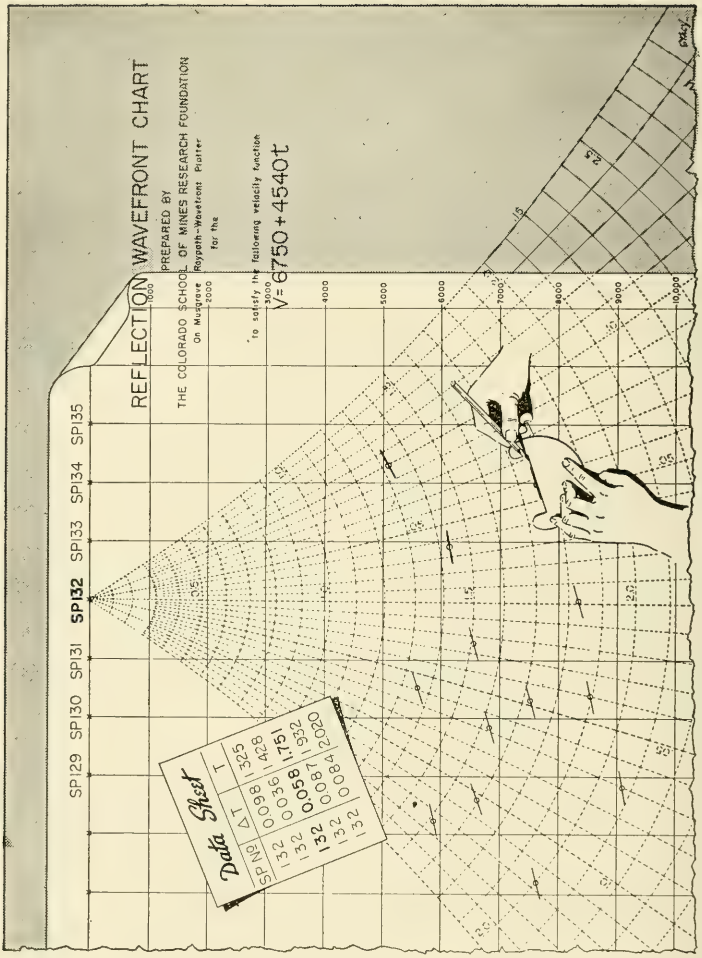
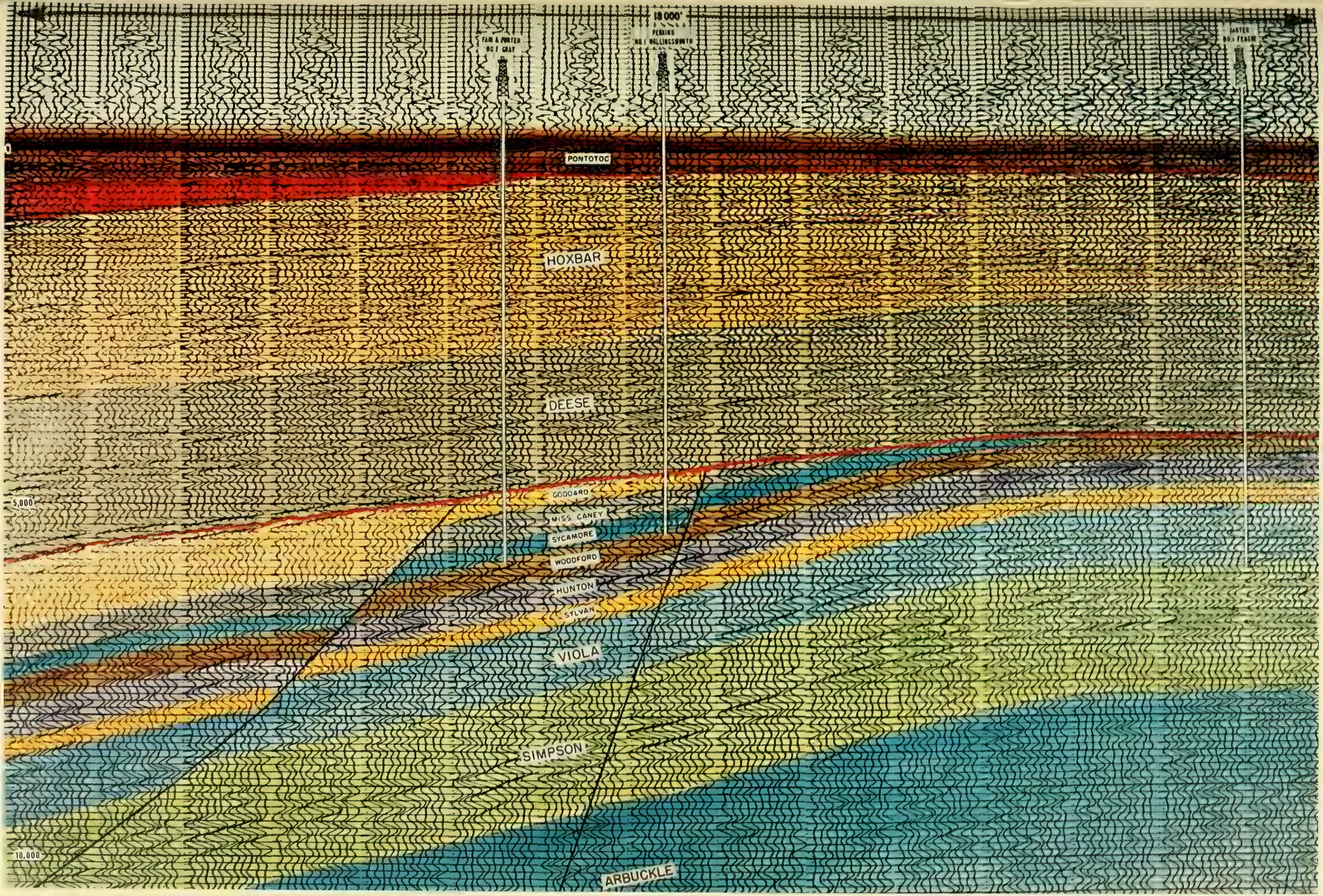
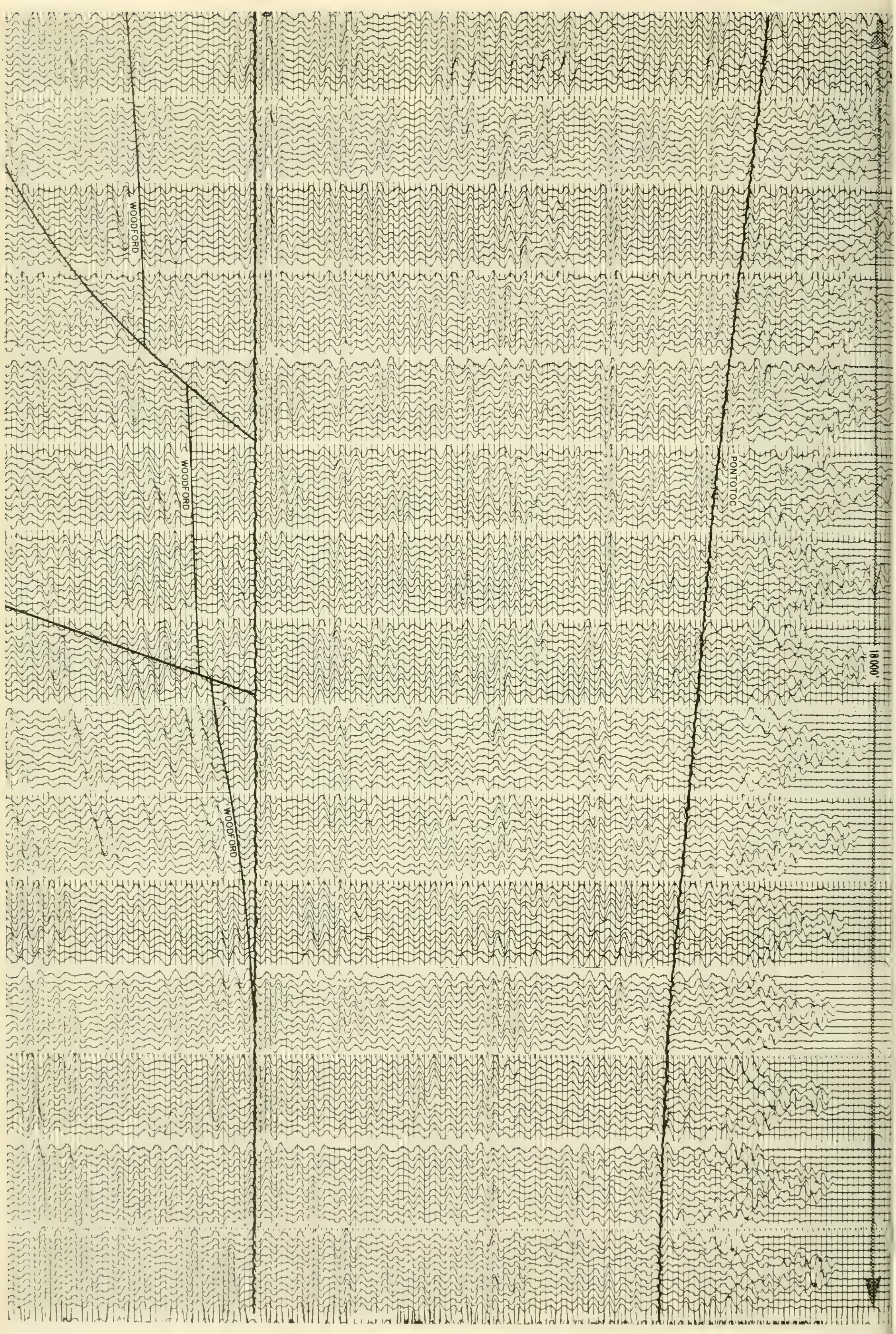


FIGURE 26-11. Illustrative example of the use of wavefront charts for the plotting of depth cross sections from seismic data (Musgrave, 1952).

FIGURE 26-12. A seismic record section reproduced from magnetically recorded data from north Healdton, Oklahoma. These data have been corrected for elevation, weathering, (LVL) and normal moveout, with each eleven trace record composited from 24 seismometer groups. It is a subsea level depth section with equal horizontal and vertical scales. Note that the stratigraphic identification is based on well data (Courtesy Geophysical Service, Incorporated).



18 000'
PONTOTOC
HOXBAR
DEESE
GODDARD
MISS. CANEY
SYCAMORE
WOODFORD
HUNTON
SYLVAN
VIOLA
SIMPSON
ARBUCKLE
5,000
10,000


WOODFORD
WOODFORD
WOODFORD
PONTOTOC
18,000'

The advent of suitable equipment for the magnetic recording and play-back of seismic data introduced a ready versatility of section display. Full record detail may be carried to the section. Individual traces or records may be shifted with respect to each other in play-back process. Thus corrections can be applied, and traces throughout the record section may be referred to any desired common datum in time or depth. Even arbitrary velocity functions may be applied to reduce time to depth. The datum may be sea level, or it may be a particular time surface, for example, an unconformity.

Desired mixing, compositing, and filtering may be accomplished at any stage in the play-back process, perhaps after all corrections have been introduced instead of being restricted to the original recording as is required by non-magnetic systems.

The resulting record section may be presented by conventional traces as illustrated in Figures 26-12 and 26-13, by the variable density tracks of Figure 26-14, by variable area tracks, or by clipped traces.

Modern record sections are most illuminating and particularly helpful in relating seismic data to the known subsurface geology. They are impressive, perhaps too impressive, and may leave the unwary viewer with a sense of complacency. He should remember that they are unmigrated representations and therefore in regions of high dip cannot represent the true subsurface.

The second general form of data presentation is the subsurface map. It may be a dip-strike map made from scattered reflection data, e.g. Salvatori (1945), but, more probably, it will be a contour map based on a reasonably continuous reflecting horizon. Contours may depict equal reflection times or depths and may be based on migrated or unmigrated points. They may purport to represent the top or bottom of a particular geologic stratum, but as pointed out previously, dependence on this relationship should be tempered by judgment.

Seismic contour maps are constructed sometimes directly from record data but more often subsequent to cross sections from which the mapper should derive great help, particularly in complicated areas.

An intriguing method of constructing a migrated map has been proposed by Hagedoorn (1954). Through the use of templates derived from the applicable velocity function, contours drawn from vertically plotted depths are translated to their migrated positions.

←

FIGURE 26-13. This seismic record section is similar to the section of Figure 26-12 except that its vertical scale is in time instead of depth, with the unconformity instead of sea level as the reference plane (Courtesy Geophysical Service, Incorporated).

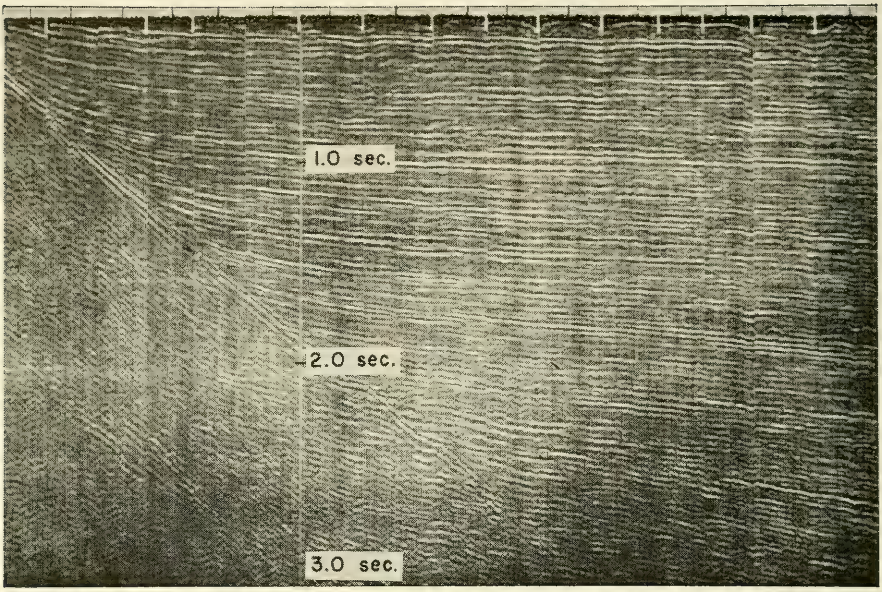


FIGURE 26-14. Portion of variable-density profile approaching flank of shallow salt dome. The steep dip arises from the near-vertical salt contact lying to the left of the section shown. (After Palmer, 1957)

The development of new techniques and instrumtentation is continually under way in the laboratories of oil companies, seismic contractors, and seismic instrument makers. The continuous velocity logger, the magnetic recording systems, and directional energy sources (multiple vertically disposed shots) are typical examples of fruition of this effort. Perhaps one of the most novel of recent developments is the "Marine Sonoprobe" (Dobrin and Dunlap, 1957). In essence a fathometer, this device displays on a continuous section the layering within the first few hundred feet of the sea bottom. Figure 26-15 shows a typical Sonoprobe profile.

As in all fields of technology, basic research in geophysics is responsible for its progress. Just as Mallet, Knott, Fessenden, Mintrop, Haseman and Karcher, and their scientific contemporaries and successors suggested and developed the seismic method, their counterparts of today may generate a new way of exploring for oil. But until they do, the seismograph will remain a dominant exploration tool.

The authors express their gratitude to E. J. Stulken and Ben Giles for their review and criticism of this chapter.

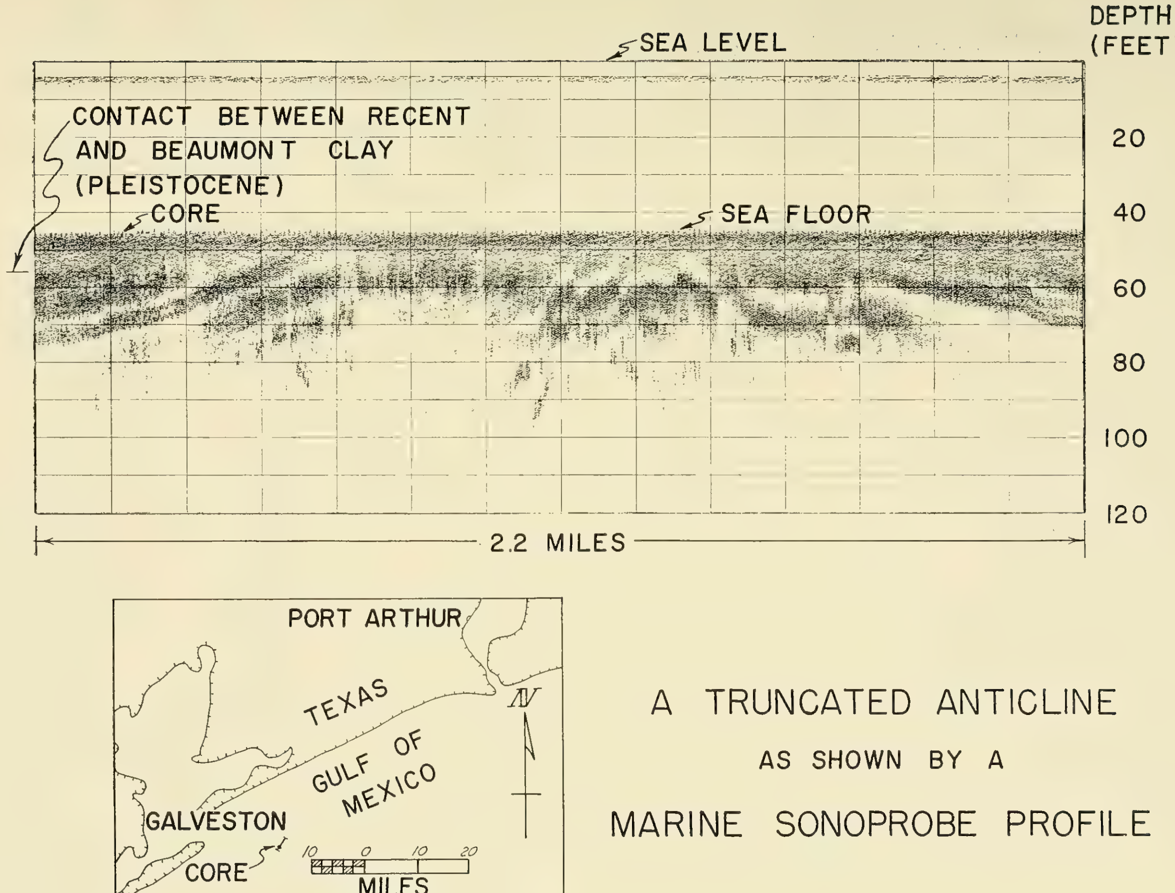


FIGURE 26-15. Marine Sonoprobe profile over a truncated anticline. (Courtesy Magnolia Petroleum Company)

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Chapter 27

GRAVITY AND MAGNETIC EFFECTS OF SUBSURFACE BODIES

P. A. Rodgers

ATTRACTION OF MASS PARTICLES

Newton's law of gravitation states that two particles of mass m_1 and m_2 attract one another with a force given by

$$F = k \frac{m_1 m_2}{r^2} \quad , \tag{1}$$

where, using the c.g.s. system of units, F is the force in dynes and r is the distance separating the particles measured in centimeters. The value used for the constant of gravitation k is 6.670×10^{-8} dyne cm.^{2}/gm.^{2}. If $\mathbf{r}$ is the vector drawn from m_1 to m_2, then the force $\mathbf{F}$ acting on m_1 would be given by

$$\mathbf{F}_1 = \frac{k m_1 m_2 \mathbf{r}}{r^3} \quad , \tag{2}$$

and the force $\mathbf{F}_2$ acting on m_2 would be given by

$$\mathbf{F}_2 = - \frac{k m_1 m_2 \mathbf{r}}{r^3} \quad . \tag{3}$$

For the purpose of studying the gravitational force field in the neighborhood of a mass particle m_1, it is convenient to associate with each point in the space about m_1 a vector representing the acceleration which would be experienced by a mass particle m_2. This vector is called the attraction of m_1 and is given by

$$\mathbf{A} = \frac{\mathbf{F}_2}{m_2} = -\frac{km_1\mathbf{r}}{r^3} \quad . \tag{4}$$

The unit of attraction in the c.g.s. system of units has been named the *gal* after Galileo. The unit commonly used in geophysical prospecting is the *milligal* or 10^{-3} gals. Sometimes a unit called a "gravity unit," equal to 10^{-4} gals, is used.

Suppose a mass particle m to be situated at a point Q whose cartesian coordinates are $(u,v,w,)$ and that we wish to write down an expression for the attraction of m at the point P whose coordinates are (x,y,z). The point occupied by the mass is called the mass point or source point. The point P is called the field point. The field point is the point where the attraction is observed or computed. It would be the point occupied by the gravity meter. Starting with equation (4) and writing $\mathbf{r}$ in terms of its components, the expression for the attraction would become

$$\mathbf{A} = -km \left[\mathbf{i}\,\frac{(x-u)}{r^3} + \mathbf{j}\,\frac{(y-v)}{r^3} + \mathbf{k}\,\frac{(z-w)}{r^3} \right], \tag{5}$$

where

$$r = [\,(x-u)^2 + (y-v)^2 + (z-w)^2\,]^{1/2}$$

From this we see that the components of the attraction are given by

$$A_x = -\,km\,\frac{(x-u)}{r^3} \tag{6}$$

$$A_y = -\,km\,\frac{(y-v)}{r^3} \tag{7}$$

$$A_z = -\,km\,\frac{(z-w)}{r^3} \tag{8}$$

Certain distributions of matter, called centrobaric, attract as though all of the mass were concentrated at a single point and for field points not enclosed by the mass may be considered as particles. Uniformly dense spheres and spherical shells are examples of such bodies. The attraction of any body of matter, not centrobaric, may be approximated by a particle of the same mass if the distance from the field point to any point within the body is large compared to the largest dimension of the body. Thus the anomaly computed for a sphere of uniform density may be helpful in studying the observed anomaly of a subsurface body whose depth of burial is large compared to its size.

To illustrate the procedure which will be used in the sequel, we will use formula (8) to compute the vertical component of the attraction of a sphere of uniform density and whose center is at a depth h below the surface.

As formula (8) stands the location and orientation of the coordinate axes with respect to the center of the sphere and the surface of the ground are not specified. The first step then is to chose a set of coordinate axes in such a way as to make the computation as simple as possible. For this purpose, we choose a set of coordinate axes in which the origin coincides with the field point, the positive z axis will be taken vertically downward and the x and y axes turned so that the center of the sphere will be in the (x,z) plane (fig. 27-1).

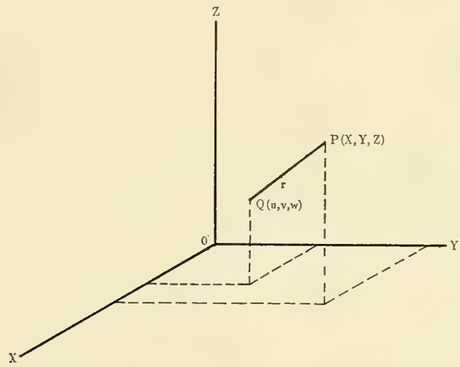


FIGURE 27-1.

The coordinates of the source point (u,v,w) now become (u,o,h) and the coordinates of the field point (x,y,z) become (o,o,o). Formula (8) may now be written

$$A_z = \frac{kmh}{(u^2 + h^2)^{3/2}} \tag{9}$$

This formula shows some improvement over formula (8) but as a working formula it has one defect, namely, that the value of the factor $\dfrac{h}{(u^2 + h^2)^{3/2}}$ would have to be recomputed every time we wanted to use a different value of h. This may be remedied by writing it in the form $\dfrac{1}{h^2} \cdot \dfrac{1}{(u^2/h^2 + 1)^{3/2}}$ or $\dfrac{1}{h^2} \cdot \dfrac{1}{(a^2 + 1)^{3/2}}$, where $a = (\dfrac{u}{h})$

We now have

$$A_z = \frac{km}{h^2} \cdot \frac{1}{(a^2 + 1)^{3/2}} \tag{10}$$

Here the dimensions are contained in the factor $\frac{km}{h^2}$ and for a particular value of h would have to be computed only once. The factor $\frac{1}{(a^2 + 1)^{3/2}}$ is dimensionless and would need be computed but once to hold for all values of h. We may think of a as u measured in units of h.

ATTRACTION OF EXTENDED BODIES

Expressions for the attraction of distributions of mass which may not be regarded as particles may be formulated by dividing the body into small elements and summing their separate attractions according to the procedure used in the calculus. Thus, the attraction $d\mathbf{A}$ of an element of mass dm situated at the source point $Q(u,v,w)$ is given at the field point $P(x,y,z)$ by

$$d\mathbf{A} = -\frac{k\mathbf{r}dm}{r^3} \tag{11}$$

or

$$d\mathbf{A} = -\frac{k\rho\mathbf{r}}{r^3}\,dudvdw \tag{12}$$

where the mass element dm has been replaced by the product of the density ρ and the volume $dudvdw$ of the element. The attraction of the entire body is then given by

$$\mathbf{A} = -k\int\int\int\frac{\rho\mathbf{r}}{r^3}\,dudvdw \tag{13}$$

and the components A_x, A_y, A_z by

$$A_x = -k\int\int\int\frac{\rho(x-u)}{r^3}\,dudvdw \tag{14}$$

$$A_y = -k\int\int\int\frac{\rho(y-v)}{r^3}\,dudvdw \tag{15}$$

$$A_z = -k\int\int\int\frac{\rho(z-w)}{r^3}\,dudvdw \tag{16}$$

Horizontal Cylinders

Suppose the body to be a horizontal cylinder of uniform cross section whose length is very great compared to the dimensions of its cross section and that we wish to find the value of A_z at points along a line at the surface perpendicular to the axis of the cylinder. As in the case of the mass particle we choose a set of coordinate axes with the origin at the field point on the surface and with the z axis vertically downward. The y axis (fig. 27-2) is turned parallel to the axis of the cylinder so that the x axis lies along the line where we wish to compute the values of A_z. We suppose the density ρ of the cylinder to be a constant.

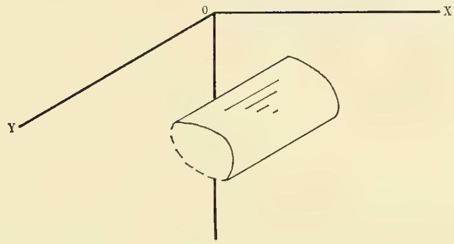


Figure 27-2.

Equation (16) may now be written

$$A_z = k\rho \int\int\int_{-\infty}^{\infty} \frac{w\,du\,dv\,dw}{(u^2 + v^2 + w^2)^{3/2}} \quad , \qquad (17)$$

where the limits $-\infty$ to ∞ refer to integration with respect to v. When the integration is carried out, equation (17) becomes

$$A_z = k\rho \int\int \frac{2w\,du\,dw}{u^2 + w^2} \quad . \qquad (18)$$

The field of integration is now the cross section of the cylinder.

Our problem at this point is to find a method of evaluating (18) which will work for a cylinder of any cross section. To do this we first consider the problem of evaluating it over the rectangle such as that shown in Figure 27-3.

We now have

$$A'_z = k\rho \int_{x_1}^{x_2} \int_{z^1}^{z^2} \frac{2w\,du\,dw}{u^2 + w^2} \qquad (19)$$

$$= k\rho \int_{x^1}^{x^2} \log\,(u^2 + z_2^2)\,du - k\rho \int_{x_1}^{x_2} \log\,(u^2 + z_1^2)\,du$$

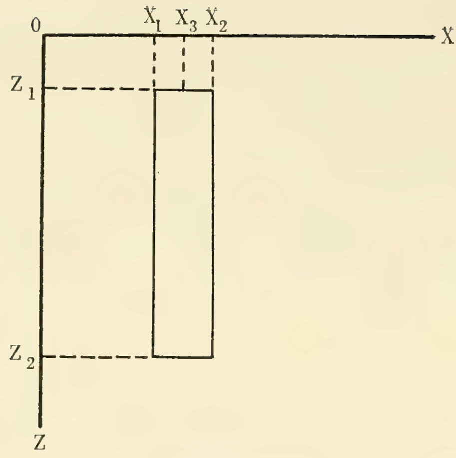


FIGURE 27-3.

If $x_2 - x_1$ is small, the change in log $(u^2 + z_2^2)$ and log $(u^2 + z_1^2)$ along the interval will be approximately linear and we may use their values at the center of the interval so that approximately

$$A'_z = k\rho\ [\ log\,(x_3^2 + z_2^2) - log\,(x_3^2 + z_1^2)\,]\ (x_2 - x_1) \tag{20}$$

To use this result to find the value of A_z for cylinders having any cross section, we first divide the area into narrow vertical rectangles as shown in Figure 27-4, evaluate the right hand side of (20) for each rectangle, and add the results. In practice this would be done by adding the values of

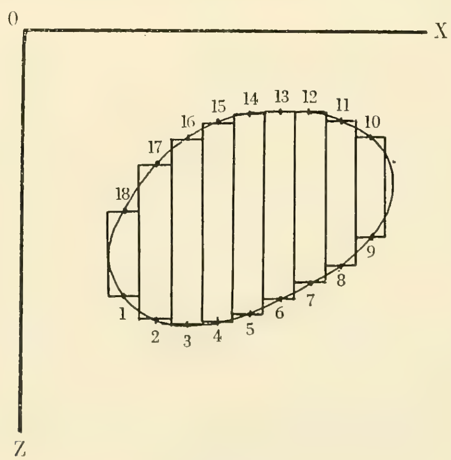


FIGURE 27-4.

$\log(x^2 + z^2)$ at the points 1, 2, · · 8, 9 and from this sum subtracting the values of $\log(x^2 + z^2)$ at the points 10, 11, · · 17, 18. The result multiplied by $k\rho(x_2 - x_1)$ would then be the value of A_z at the point $(x = 0, z = 0)$.

What is needed is a quick method of finding $\log(x^2 + z^2)$ at each of the points 1, 2, · · 17, 18. One way of doing this is to draw a contour map of $\log(x^2 + z^2)$ and superpose it on the cross section of the body. The principle is the same as that used in showing elevations at points on a map by drawing contour lines at suitable intervals through points of equal height above sea level. The contour lines of $\log(x^2 + z^2)$ are circles with centers at the origin. Table 27-I gives the radii of the circles corresponding to values of $\log r^2 = \log(x^2 + z^2)$ at intervals of 1/10 from $\log r^2 = 0$ to $\log r^2 = 9.20$.

The contours should be inked on cross section paper with certain contours identified with the value of $\log r^2$, say every other one, similar to the way contours are identified on topographic maps. The outline of the body may then be drawn lightly with pencil on the contour map itself or drawn on a piece of tracing paper and laid over the contour map. The lines dividing the area into rectangles need not actually be drawn since the vertical lines ruled on the cross section paper will serve the purpose just as well. There is an advantage in drawing the outline of the figure on a separate sheet of paper when there are several points to be computed along a profile across the body. In this case it is much easier to move the outline of the figure with respect to the origin on the contour map than it is to sketch the figure on the contour map for each new point to be computed.

To illustrate the method, we will use it to compute the value of A_z at two points above a horizontal cylinder of circular cross section. Suppose the cylinder to have a radius of 100 meters, its center to be at a depth of 300 meters below the surface, and its density to be 1 gm. per cm.^{3} higher than that of the surrounding materials. Let one of the field points be vertically over the center of the cylinder and the other 200 meters away from the projection of the center of the cylinder on the surface.

Figure 27-5 is a contour map of $\log(x^2 + z^2)$ with the outline of the cylinder drawn to proper scale and position. In this case the unit used in drawing the contour map has been set equal to 100 meters. This choice will place the center of the cylinder in the two positions 3 units below the x axis or surface of the ground and will give the radius of the cylinder the value 1 unit. Any other choice for the value of the unit that would permit the outline of the cylinder to be drawn on the contour map would work just as well. For example, if the unit had been set equal to 200 meters, the center of the cylinder would have been 1½ units below the surface and its radius equal ½ unit. The width of the rectangles into which the body is divided has been chosen to be ¼ unit, which gives $x_2 - x_1$ the value 25 meters or 2500 cm.

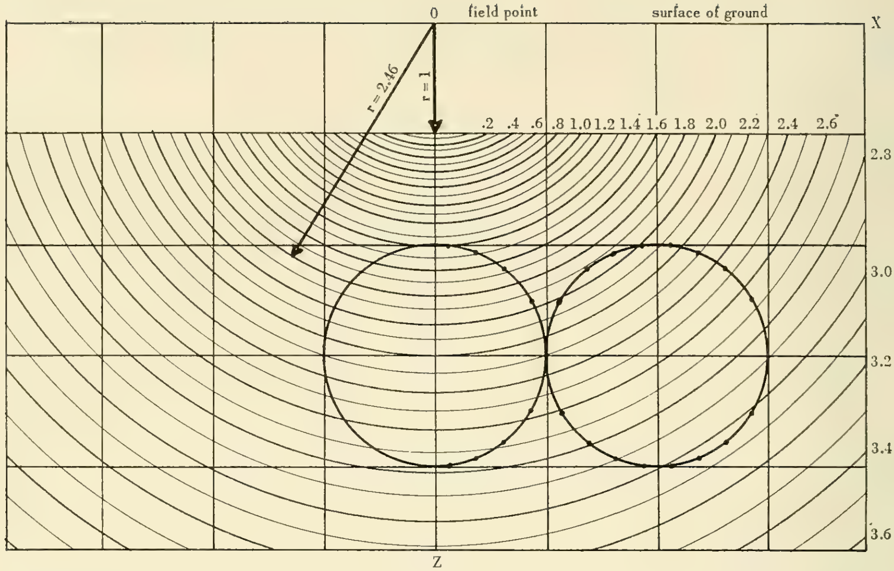


FIGURE 27-5. Contour map of log $(x^2 + z^2) = \log r^2$ with outlines of cylinder in two positions.

Tabulating the values of $\log(x_3{}^2 + z^2)$ at the points on the periphery of the cylinder indicated by dots, we get

for point above cylinder	*for point to left of cylinder*	
2.77	2.69	−2.66
2.74	2.79	−2.45
2.69	2.90	−2.29
2.56	2.97	−2.14
−1.94	3.03	−2.01
−1.67	3.05	−1.93
−1.48	3.06	−1.91
−1.40	3.03	−2.02
$4.27 \times 2 = 8.54$	23.43	$-17.41 = 6.02$

The attraction component A_z at the two points is then

$$A_z = 6.67 \times 10^{-8} \times 1 \times 8.54 \times 2500$$
$$= 1.42 \text{ milligals}$$

$$A_z = 6.67 \times 10^{-8} \times 1 \times 6.02 \times 2500$$
$$= 1.00 \text{ milligals}$$

Vertical Cylinders

A method much like the one just described for infinite horizontal cylinders may also be used to compute the gravity effect of vertical cylinders or prisms of finite length. In this case we start with the problem of computing A_z for a body with vertical sides, whose top end is plane and at a depth h below the surface of the ground and whose lower end is at infinity (fig. 27-6).

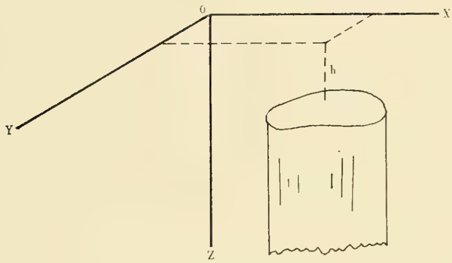


FIGURE 27-6.

As before, we take the field point at the origin of coordinates so that equation (16) reduces to

$$A_z = kp \int\int\int_h^\infty \frac{wdudvdw}{(u^2 + v^2 + w^2)^{3/2}} = kp \int\int \frac{dudv}{(u^2 + v^2 + h^2)^{1/2}} \quad (21)$$

In the integral

$$\int\int \frac{dudv}{(u^2 + v^2 + h^2)^{1/2}}$$

we set $u = ha$, $v = hb$, so that

$$A_z = kph \int\int \frac{dadb}{(a^2 + b^2 + 1)^{1/2}} \quad (22)$$

Evaluating (22) over the narrow rectangle shown in Figure 27-7 we get approximately

$$A'_z = kph \Big[\log \left(x_2 + \sqrt{x_2^2 + y_3^2 + 1}\right) \quad (23)$$

$$- \log \left(x_1 + \sqrt{x_1^2 + y_3^2 + 1}\right)\Big] (y_2 - y_1)$$

A contour map of $\log \left(x + \sqrt{x^2 + y^2 + 1}\right)$ for positive values of x is shown in Figure 27-8. The images of the contours on the positive side of the y

axis have been used on the negative side. The reason for this is that the contours computed for the negative side of the y axis crowd in so close to the x axis the map becomes inconvenient to use in this part.

Tables 27-II, 27-III, 27-IV, 27-V contain coordinates of points to be used in plotting the contours of $c = log\left(x + \sqrt{x^2 + y^2 + 1} \right)$ at intervals of 1/10 from $c = .1$ to $c = 3.0$. Table 27-V gives the coordinates of the points where the contours cross the y axis.

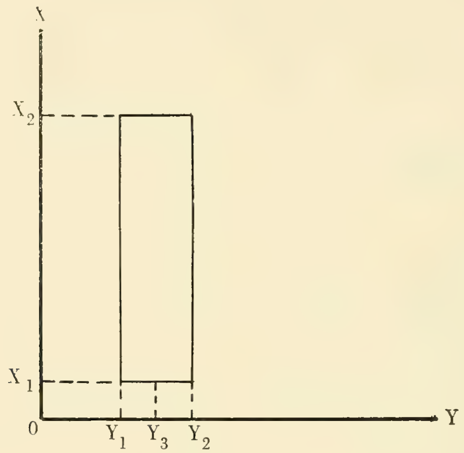


FIGURE 27-7.

The procedure followed in computing A_z for semi-infinite vertical cylinders or prisms is roughly the same as that used in the two dimensional case except that the outline of the body is measured in units of the depth h. To compute A_z for a cylinder of finite length, the top being at a depth h_1 and the bottom at depth h_2, the computation is carried out for two semi-infinite cylinders, their tops being at depth h_1 and h_2 respectively. The value of A_z for the cylinder of length $(h_2 - h_1)$ is then the difference between the two attractions of the semi-infinite cylinders. If the outline of the cylinder falls partly above and partly below the y axis, the computation for each of the two parts must be carried out separately, that is, as though there were two different bodies each bounded on one side by the y axis.

For a sample calculation, let the given body be rectangular in cross section measuring 300 feet by 200 feet on the sides and let the depths to its top and bottom surfaces be 100 feet and 300 feet respectively. Two calculations must

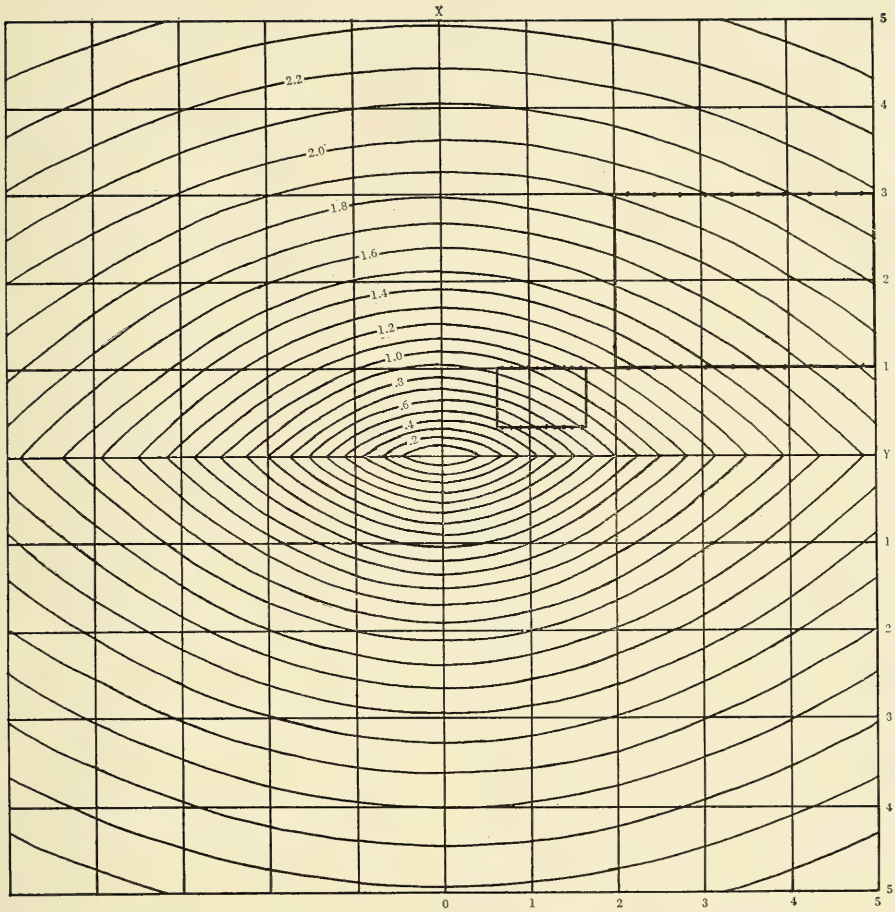


FIGURE 27-8. Contour map of log $(x + \sqrt{x^2 + y^2 + 1})$

be carried out, one for the semi-infinite prism whose top is 100 feet below the surface and one for that whose top is 300 feet below the surface. Suppose the long edge of the body to run east and west and that the point where we wish to compute A_z is 200 feet west and 100 feet south of the southwest corner of the body. Then, the positive direction of the x axis being taken north, the southwest corner of the shallower body would be placed at the point $x = 2, y = 1$ and that for the deeper body at the point $x = 2/3, y = 1/3$. In units of the contour map the shallower body would measure 3 units by 2 units while the deeper body would measure 1 unit by 2/3 unit.

Figure 27-8 shows the contour map with the superposed outlines of the two bodies. The values of log $\left(x + \sqrt{x^2 + y^2 + 1}\right)$ have been estimated at the points indicated by dots on the outlines of the two bodies and the results tabulated below.

Large rectangle			*Small rectangle*		
1.92	−1.28		.95	−.47	
1.94	−1.35		.97	−.50	
1.97	−1.42		.99	−.54	
2.00	−1.48		1.00	−.58	
2.03	−1.54		1.03	−.62	
2.06	−1.59		1.05	−.66	
2.09	−1.65		1.07	−.70	
2.12	−1.71		1.10	−.74	
2.14	−1.75		1.12	−.77	
2.18	−1.80		1.15	−.82	
20.45	−15.57	= 4.88	10.43	−6.40	= 4.03

In the case of the large rectangle the value of $y_2 - y_1$ is 3/10 units while for the small rectangle its value is 1/10 unit. If we use 1 gm./cm.^{3} for the value of ρ and express h_1 and h_2 in centimeters, the value of A_z for the body whose vertical dimension is $(h_2 - h_1)$ will be

$$\begin{aligned} A_z &= k\rho h_1\ (4.88)\ (0.3) - k\rho h_2 (4.03)\,(.1) \\ &= (6.67 \times 10^{-8})\ (3048)\ (4.88)\ (0.3) - (6.67 \times 10^{-8})\ (9144) \\ &\quad (4.03)\,(0.1) = 0.05 \text{ milligal} \end{aligned}$$

Solid Angles

The vertical component of attraction of a subsurface body may also be computed by dividing it into thin horizontal slabs and supposing the mass of each slab to be concentrated on a very thin lamina coinciding with the center of the slab. The attraction component A_z of each of the lamina is then proportional to the solid angle subtended by the lamina at the point on the surface where A_z is to be computed.

To compute the solid angle subtended by the lamina, we notice first that A_z is given by

$$A_z = k\sigma \int\int \frac{h}{(u^2 + v^2 + h^2)^{3/2}}\, dudv \quad , \tag{24}$$

where σ is the mass per unit area of the lamina and h is its depth. Since $r = (u^2 + v^2 + h^2)^{1/2}$ and $\cos\theta = h/r$ (fig. 27-9), we may write the expression for A_z in the form

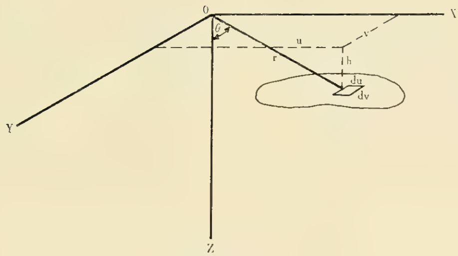


FIGURE 27-9.

$$A_z = k\sigma \iint \frac{\cos\theta du dv}{r^2} \tag{25}$$

$$= k\sigma \int d\Omega = k\sigma\Omega \quad ,$$

where Ω is the solid angle subtended by the lamina at the origin of coordinates. If we measure u and v in units of h, we see that

$$\Omega = \iint \frac{du dv}{(u^2 + v^2 + 1)^{3/2}} \tag{26}$$

By dividing the lamina into narrow rectangular strips and computing the solid angle subtended by each strip, we can find a sufficiently good approximation to Ω. The solid angle Ω' subtended by the strip shown in Figure 27-7 is given approximately by

$$\Omega' = \left\{ \frac{x_2}{(y_3^2+1)(x_2^2+y_3^2+1)^{1/2}} - \frac{x_1}{(y_3^2+1)(x_1^2+y_3^2+1)^{1/2}} \right\} (y_2 - y_1) \tag{27}$$

A map of the function $\dfrac{x}{(y^2 + 1)(x^2 + y^2 + 1)^{1/2}}$ may be plotted from values given in Table 27-VI. This map is shown in Figure 27-10.

MAGNETIC EFFECTS

In the problem of computing magnetic fields of magnetized bodies the quantity corresponding to mass is called the *magnetic moment* of the body, and the magnetic moment per unit of volume, the quantity corresponding to mass density, is called the *intensity of magnetization.* In the attraction problem we use the

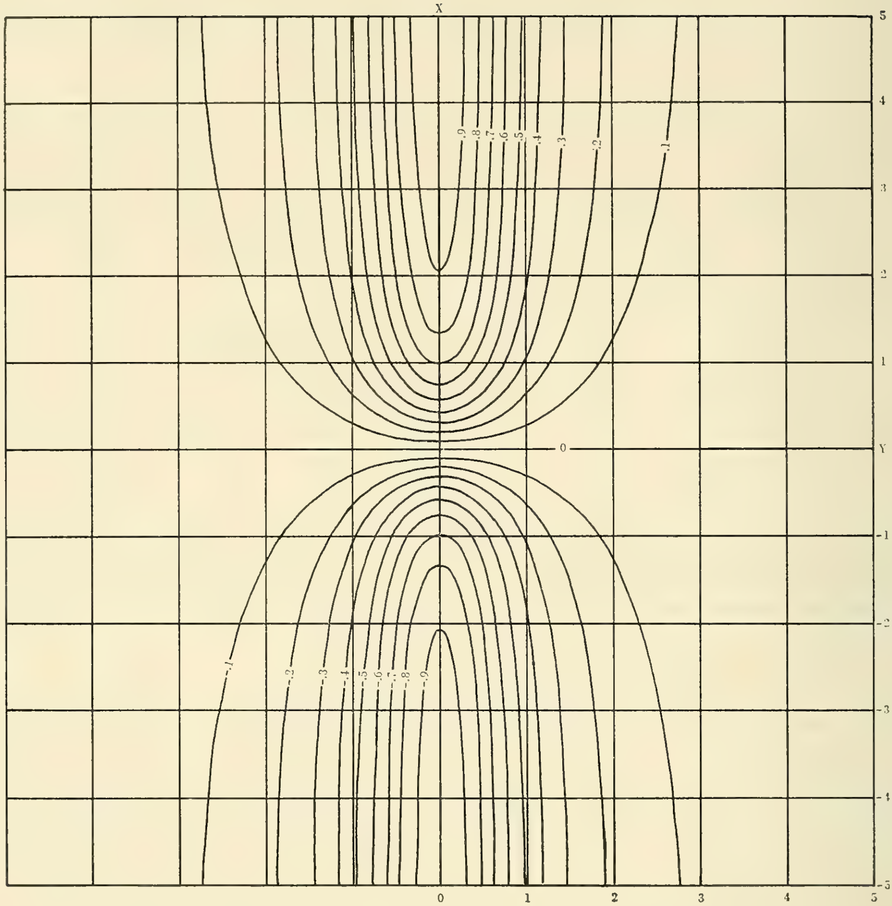


FIGURE 27-10. Contour map of the function $\dfrac{x}{(y^2+1)\ (x^2+y^2+1)^{1/2}}$

idea of a mass particle in which we associate a mass m with a point. In the magnetic problem we use the idea of a magnetic particle in which we associate a magnetic moment $\mathbf{m}$ with a point.

The concepts of magnetic field, magnetic moment, and magnetic particle may be developed from Coulomb's law of force for magnetic poles,

$$F = c\frac{p_1 p_2}{r^2} \tag{28}$$

Here p_1 and p_2 represent two point magnetic poles, r the distance separating them, and F the force on either arising from the presence of the other. In the electromagnetic system of units $c = 1$ and its units are suppressed. Unit poles are defined such that two equal poles will exert a force upon one another of one dyne when separated by a distance of one centimenter. If p_1 and p_2 have the same sign, the force is one of repulsion. If they have opposite signs, the force is one of attraction.

If $\mathbf{r}$ be the vector drawn from p_1 to p_2, then the force $\mathbf{F}_1$ acting on p_1 will be given by

$$\mathbf{F}_1 = -\frac{p_1 p_2 \mathbf{r}}{r^3} \quad , \tag{29}$$

and the force $\mathbf{F}_2$ acting on p_2 by

$$\mathbf{F}_2 = \frac{p_1 p_2 \mathbf{r}}{r^3} \quad . \tag{30}$$

We associate with each point in the space about a pole p a vector $\mathbf{H}$ defined by

$$\mathbf{H} = \frac{p\mathbf{r}}{r^3} \quad . \tag{31}$$

The vector $\mathbf{H}$, called the magnetic intensity, represents the force in dynes which would be exerted on a unit pole if placed a distance r from a pole p. The unit of $\mathbf{H}$ in the electromagnetic system is called the oersted. The unit used in geophysical prospecting is equal to 10^{-5} oersteds and is called the gamma.

If the pole p be placed at a point whose coordinates are (u,v,w), then the magnetic intensity $\mathbf{H}$ at a point whose coordinates are (x,y,z) would be given by

$$\mathbf{H} = p\left[\mathbf{i}\frac{(x-u)}{r^3} + \mathbf{j}\frac{(y-v)}{r^3} + \mathbf{k}\frac{(z-w)}{r^3}\right] , \tag{32}$$

where $r = [(x-u)^2 + (y-v)^2 + (z-w)^2]^{1/2}$. This may be written

$$\mathbf{H} = -\mathbf{i}\frac{\partial}{\partial x}\left(\frac{p}{r}\right) - \mathbf{j}\frac{\partial}{\partial y}\left(\frac{p}{r}\right) - \mathbf{k}\frac{\partial}{\partial z}\left(\frac{p}{r}\right) , \tag{33}$$

from which we have

$$H_x = -\frac{\partial}{\partial x}\left(\frac{p}{r}\right) \tag{34}$$

$$H_y = -\frac{\partial}{\partial y}\left(\frac{p}{r}\right) \tag{35}$$

$$H_z = -\frac{\partial}{\partial z}\left(\frac{p}{r}\right) \tag{36}$$

The quantity p/r whose negative derivatives give the field components is called the potential of p.

The magnetic particle corresponding to the mass particle is called a magnetic dipole. We might think of a mass particle as being formed by starting with a body of any shape and imagining its dimensions to shrink toward a point while at the same time supposing its density to increase in such a way that its mass remains constant. The idea of a magnetic dipole may be formed in a similar way.

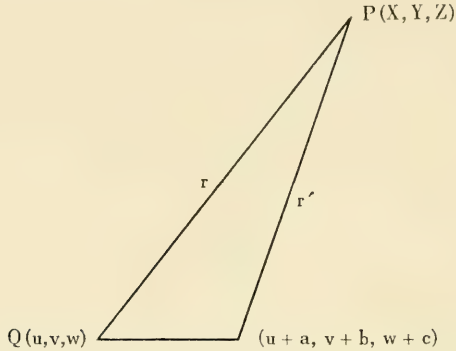


FIGURE 27-11.

Starting with two poles of strength p and $-p$, let the coordinates of the negative pole be (u,v,w) and those of the positive pole $(u + a,\ v + b,\ w + c)$. The potential V of such a pair at a point $P(x,y,z)$ distant r and r' from the negative and positive poles respectively is given by (fig. 27-11)

$$V = \frac{p}{r} - \frac{p}{r'} \tag{37}$$

By means of Taylor's expansion for a function of three variables, this may be written

$$V = p\left(a\frac{\partial}{\partial u} + b\frac{\partial}{\partial v} + c\frac{\partial}{\partial w}\right)\left(\frac{1}{r}\right) + p\left(a\frac{\partial}{\partial u} + p\frac{\partial}{\partial v} + c\frac{\partial}{\partial w}\right)^2\left(\frac{1}{r}\right) + \cdots$$

or, if $\mathbf{A} = \mathbf{i}a + \mathbf{j}b + \mathbf{k}c$ and $\nabla = \mathbf{i}\dfrac{\partial}{\partial u} + \mathbf{j}\dfrac{\partial}{\partial v} + \mathbf{k}\dfrac{\partial}{\partial w}$, (38)

$$V = p\mathbf{A}\cdot\nabla\left(\frac{1}{r}\right) + p\,(\mathbf{A}\cdot\nabla)^2\left(\frac{1}{r}\right) + \cdots \tag{39}$$

The vector $\mathbf{m} = p\mathbf{A}$ is called the magnetic moment of the pole pair $-p$ and p. If now $|\mathbf{A}|$ be made to decrease and p to increase in such a way that $\mathbf{m}$ remains constant, all terms after the first in (39) will approach zero and the limiting value of the potential will be $\mathbf{m} \cdot \nabla \left(\frac{1}{r}\right)$. This quantity is the potential of a magnetic particle or dipole of magnetic moment **m**.

If we think of a magnetized body as being built up of dipole elements, then the magnetic moment of the body will be the vector sum of the magnetic moments of the individual dipoles. Let the magnetic moment per unit volume or intensity of magnetization be designated by **I**. The magnetic moment of a volume element $dudvdw$ would then be $\mathbf{I}dudvdw$ and its magnetic potential $\mathbf{I} \cdot \nabla \left(\frac{1}{r}\right) dudvdw$. The potential of the entire body would then be given by

$$V = \iiint \mathbf{I} \cdot \nabla \left(\frac{1}{r}\right) dudvdw \tag{40}$$

or, if (l,m,n) be the direction cosines of **I**, by

$$V = I \iiint \left[l \frac{\partial}{\partial u}\left(\frac{1}{r}\right) + m \frac{\partial}{\partial v}\left(\frac{1}{r}\right) + n \frac{\partial}{\partial w}\left(\frac{1}{r}\right) \right] dudvdw. \tag{41}$$

The components of **I** will be in general functions of the source point coordinates (u,v,w). In what follows we shall suppose **I** to remain constant.

Vertical Component of Field of Infinite Horizontal Cylinder

As in the problem of computing the vertical component of the attraction of the horizontal cylinder, let the coordinate axes be chosen such that the z axis is vertically downward and the y axis is parallel to the axis of the cylinder. The x,y plane is supposed to coincide with the surface of the ground. Let the direction cosines of **I** in such a system be (l, m, n).

The potential V at a point whose coordinates are (x,y,z) will be given by

$$V = I \iint \int_{-\infty}^{\infty} \left[l \frac{\partial}{\partial u} \left(\frac{1}{r}\right) + n \frac{\partial}{\partial w} \left(\frac{1}{r}\right) \right] dudvdw \quad , \tag{42}$$

since the term containing m as a factor has the value zero. The limits $-\infty$ and ∞ refer to integration with respect to v. When this integration is performed (42) becomes

$$V = 2I \iint \frac{[l\,(x-u) + n\,(z-w)]}{(x-u)^2 + (z-w)^2}\, dudw \quad . \tag{43}$$

The field component $H_z = -\frac{\partial V}{\partial z}$, *so that at the point* $(x,y,z,)$

$$H_z = 4Il \int\int \frac{(x-u)(z-w)}{[(x-u)^2+(z-w)^2]^2}\, dudw \tag{44}$$

$$- 2In \int\int \frac{(x-u)^2-(z-w)^2}{[(x-u)^2+(z-w)^2]^2}\, dudw$$

At the point (o,o,o) equation (44) reduces to

$$H_z = 2Il \int\int \frac{2uw}{(u^2+w^2)^2}\, dudw - 2In \int\int \frac{u^2-w^2}{(u^2+w^2)^2}\, dudw, \tag{45}$$

which may be written

$$H_z = -2Il \int\int \frac{\partial}{\partial u} \left(\frac{w}{u^2+w^2}\right) dudw - 2In \int\int \frac{\partial}{\partial w} \left(\frac{w}{u^2+w^2}\right) dudw \tag{46}$$

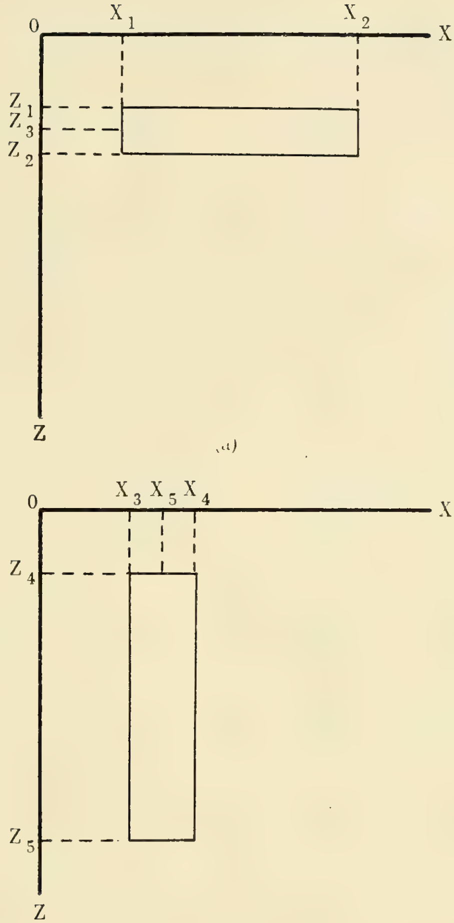
Following the method used in computing the attraction of horizontal cylinders we will first evaluate the integrals in equation (46) over narrow rectangles, the first integral over a rectangle such as that shown in Figure 27-12a and the second over one such as that shown in Figure 27-12b. If $(z_2 - z_1)$ and $(x_4 - x_3)$ are small, a good approximation to the first integral is given by

$2Il \left(\frac{z_3}{x_1^2 + z_3^2} - \frac{z_3}{x_2^2 + z_3^2}\right) (z_2 - z_1)$ and to the second by

$2In \left(\frac{z_4}{x_5^2 + z_4^2} - \frac{z_5}{x_5^2 + z_5^2}\right) (x_4 - x_3)$.

The function to be mapped is $\frac{z}{x^2 + z^2}$. The contours are circles passing through the origin with centers on the z axis. The radii of the circles corresponding to constant values of $\frac{z}{x^2 + z^2}$ are given in Table 27-VII. The contour map is shown in Figure 27-13.

There is one difference between the use of this map and that of the maps described previously. In the present case two counts must be made around the boundary of the body, one for the terms containing the factor Il and one for the terms containing the factor In. For the terms containing the factor Il the cross section of the body is divided into horizontal rectangles so that on the left hand side of the body the values of $\frac{z}{x^2 + z^2}$ read off the map will be



(b)

FIGURE 27-12.

given the positive sign while those values read on the right hand side will be given the negative sign. For the terms containing *In*, vertical rectangles are used and values of $\frac{z}{x^2 + z^2}$ read at the upper end of the rectangles have the positive sign and values read at the bottom end the negative sign.

Example: Suppose the cylinder to have a circular cross section, its radius to be 100 meters and its axis to be 250 meters below the surface of the ground. Suppose further that its axis runs east and west and that its magnetization

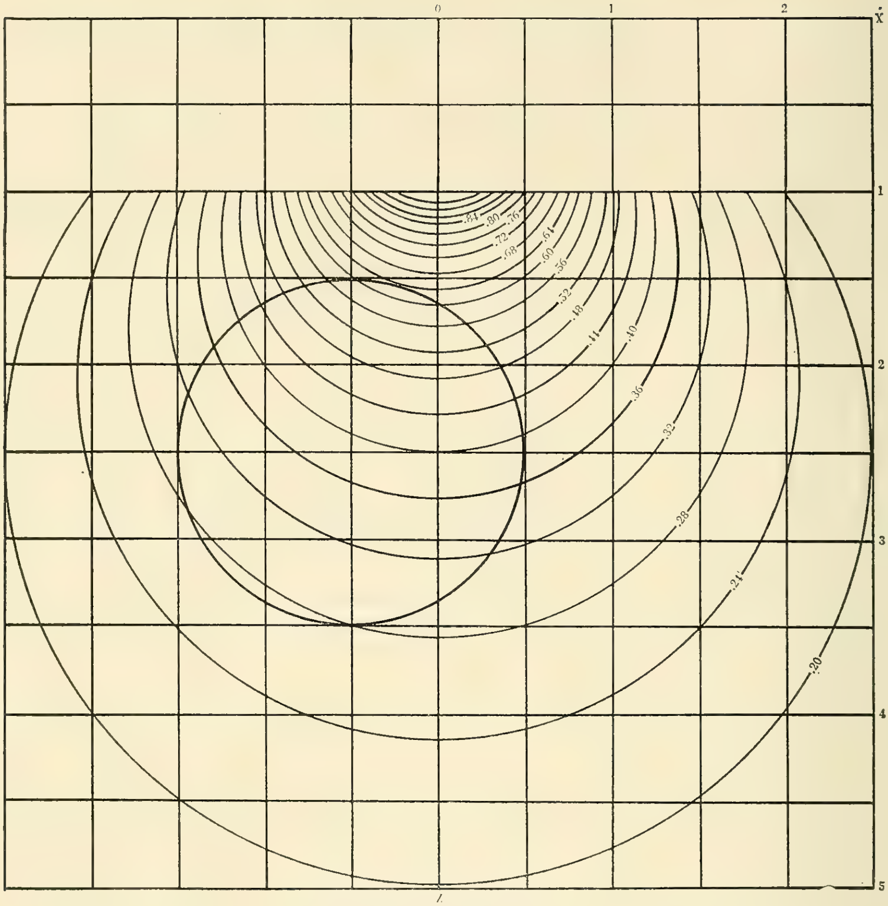


FIGURE 27-13. Contour map of the function $\dfrac{z}{x^2 + z^2}$

$I = .002$ and is in the direction of the earth's magnetic field at a point on the earth's surface where the inclination of the earth's field with the horizontal is 60 degrees. Let it be required to compute the value of H_z arising from the cylinder at a point on the surface of the ground 50 meters north of the vertical projection of the axis on the surface.

If the unit of the contour map be set equal to 100 meters, then the center of the circular outline of the cylinder will fall $2\frac{1}{2}$ units below the x axis and $\frac{1}{2}$ unit to the left of the z axis. To find the contribution to H_z of the terms containing In, we use the tenth unit divisions on the cross-section paper on which the contour map is drawn to divide the circular area into vertical rectangles. Values of $\dfrac{z}{x^2 + z^2}$ at the ends of each rectangle are then read off the contour map and either recorded or put into a calculating machine. These values are given the positive sign if read at the top of the circle and the negative sign if read at the bottom. The contribution to H_z of the term containing Il is computed in the same way except that horizontal rectangles are used. The values read off the map were recorded as follows:

For terms containing In		*For terms containing Il*	
.316	−.348	.276	−.290
.347	−.327	.274	−.299
.372	−.315	.273	−.308
.404	−.308	.275	−.314
.431	−.302	.276	−.323
.467	−.295	.278	−.332
.495	−.292	.282	−.343
.522	−.288	.285	−.354
.555	−.286	.289	−.365
.585	−.284	.293	−.378
.610	−.280	.298	−.392
.625	−.278	.306	−.409
.633	−.276	.312	−.428
.632	−.275	.321	−.450
.618	−.274	.334	−.472
.592	−.273	.350	−.498
.563	−.273	.371	−.528
.530	−.274	.400	−.565
.490	−.277	.445	−.600
.440	−.283	.510	−.615
sum	4.420	sum	−1.815

Using $I = .002$, $n = .866$, $l = .5, x_4 - x_3 = .1$, $z_2 - z_3 = .1$, we get and for the Il terms

$$2nI(4.42)(x_4 - x_3) = 2(.866)(.002)(4.42)(.1) = 153 \text{ gammas}$$

and for the Il terms

$$2lI(-1.815)(z_2 - z_1) = 2(.5)(.002)(-1.815)(.1) = -36 \text{ gammas}$$

The sum of these two terms yields $H_z = 117$ gammas.

Vertical Component H_z of Field of Vertical Cylinder

In this case the coordinate axes are chosen such that the y axis is perpendicular to the direction of magnetization and as before with the positive z

axis vertically downward. With axes chosen in this way the direction cosines are (l,o,n) and the potential

$$V = I\iiint\left[l\,\frac{\partial}{\partial u}\left(\frac{1}{r}\right) + n\,\frac{\partial}{\partial w}\left(\frac{1}{r}\right) \right] du\,dv\,dw \qquad (47)$$

The field component $H_z(x,y,z)$ will then be given by

$$H_z(x,y,z) = I\iint\int_h^{\infty}\left[l\,\frac{\partial^2}{\partial u\,\partial w}\left(\frac{1}{r}\right) + n\,\frac{\partial^2}{\partial w^2}\left(\frac{1}{r}\right)\right] du\,dv\,dw, \qquad (48)$$

the integration between the limits h and ∞ being carried out with respect to w. The result of this step is

$$H_z(x,y,z) = -\,\mathrm{I}\iint \frac{l\,(x-u) + n\,(z-h)}{[(x-u)^2 + (y-v)^2 + (z-h)^2]^{3/2}}\,du\,dv \qquad (49)$$

At the point (o,o,o) this becomes

$$H_z(o,o,o) = \mathrm{I}\iint \frac{lu + nh}{(u^2 + v^2 + h^2)^{3/2}}\,du\,dv. \qquad (50)$$

If we measure u and v in units of h and take as the field of integration the narrow rectangle shown in Figure 27-7 we get approximately

$$H_z = I\left\{\frac{nx_2}{(y_3^2+1)\,(x_2^2+y_3^2+1)^{1/2}} - \frac{l}{(x_2^2+y_3^2+1)^{1/2}}\right\}(y_2 - y_1)$$

$$-\,I\left\{\frac{nx_1}{(y_3^2+1)\,(x_1^2+y_3^2+1)^{1/2}} - \frac{l}{(x_1^2+y_3^2+1)^{1/2}}\right\}(y_2 - y_1) \qquad (51)$$

The function to be mapped is

$$f(x,y) = \frac{nx}{(y^2+1)\,(x^2+y^2+1)^{1/2}} - \frac{l}{(x^2+y^2+1)^{1/2}}\quad .$$

Table 27-VIII gives values of (x,y) which may be used to map this function for **I** inclined at an angle of 60 degrees. A contour map plotted from this table is shown in Figure 27-14. It may be used to compute fields of vertical cylinders or prisms in a way similar to that described for computing the vertical component of attraction A_z of a vertical cylinder or prism.

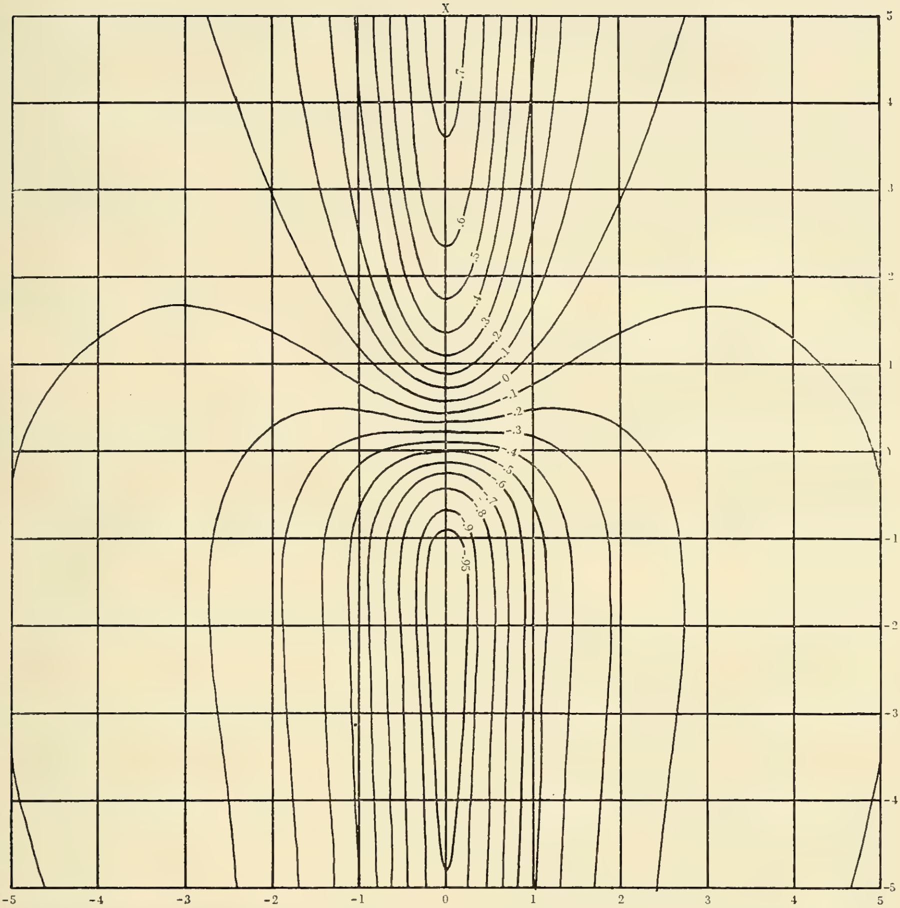


FIGURE 27-14. Contour map of function $\dfrac{nx}{(y^2+1)(x^2+y^2+1)^{1/2}} - \dfrac{l}{(x^2+y^2+1)^{1/2}}$

Anomalies Measured with the Airborne Magnetometer

The airborne magnetometer measures the component of the local anomaly in the direction of the earth's total magnetic field. Since the total field is the sum of the main field and the field arising from magnetized bodies near the surface of the earth, the direction of the total field is changed in the neighborhood of these bodies so that the direction of the measured anomaly component does not remain fixed with respect to a given coordinate system.

The same thing may be said in regard to the gravity meter. It measures the component of the anomaly in the direction of the earth's total gravitational field whose direction is influenced slightly by the local anomaly one may be trying to measure. However, the part of the field arising from local bodies is very small so that changes in the direction of the field may be safely ignored.

So too, if the anomalous part of the earth's magnetic field is small compared to the main field we may neglect changes in the direction of the total field due to local anomalies. Accordingly, when we calculate anomalies measured with the airborne magnetometer, we calculate the component along a fixed direction and keep in mind that our results can be expected to compare with that measured with the airborne instrument only when the anomaly field is small compared to the earth's main field.

Field Component of Infinite Horizontal Cylinder Measured by the Airborne Magnetometer

We use the same orientation of the coordinate axes used in computing H_z for the horizontal cylinder. Let it be required to compute the component of **H** in the direction of a line whose direction cosines with respect to this system are (α,β,γ). Since there will be no component of **H** in the direction of the y axis, the component of **H** along the line whose direction cosines are (α,β,γ) will be given by

$$H_s = \alpha H_x + \gamma H_z \tag{25}$$

From equation (43) the potential

$$V = 2I \int\int \frac{[\,l\,(x - u) + n\,(z - w)\,]}{(x - u)^2 + (z - w)^2}\, dudw \quad . \tag{53}$$

At the point (x,y,z)

$$H_x(x,y,z) = -\frac{\partial V}{\partial x} = 2Il \int\int \frac{(x-u)^2 - (z-w)^2}{[(x-u)^2 + (z-w)^2]^2}\, dudw \tag{54}$$

$$+\, 2In \int\int \frac{2\,(x-u)\,(z-w)}{[(x-u)^2 + (z-w)^2]^2}\, dudw \quad ,$$

and at the origin of coordinates

$$H_x(o,o,o) = 2Il \int\int \frac{u^2 - w^2}{(u^2 + w^2)^2} dudv + 2In \int\int \frac{2uw}{(u^2 + w^2)^2} dudw \tag{55}$$

$$= 2Il \int\int \frac{\partial}{\partial w}\left(\frac{w}{u^2 + w^2}\right) dudw - 2In \int\int \frac{\partial}{\partial u}\left(\frac{w}{u^2 + w^2}\right) dudw$$

When we evaluate these two integrals, the first over the rectangle of Figure 27-12a and the second over the rectangle of Figure 27-12b we get

$$-2Il \left(\frac{z_4}{x_5^2 + z_4^2} - \frac{z_5}{x_5^2 + z_5^2} \right) (x_4 - x_3)$$

and $$2In \left(\frac{z_3}{x_1^2 + z_3^2} - \frac{z_3}{x_2^2 + z_3^2} \right) (z_2 - z_1)$$

Using the result already found for H_z (equation 46 and sequel), we find that to compute H_s we must sum such terms as

$$(2Ina + 2Il\gamma) \left(\frac{z_3}{x_1^2 + z_3^2} - \frac{z_3}{x_2^2 + z_3^2} \right) (z_2 - z_1)$$

for horizontal rectangles and such terms as

$$(2In\gamma - 2Ila) \left(\frac{z_4}{x_5^2 + z_4^2} - \frac{z_5}{x_5^2 + z_5^2} \right) (x_4 - x_3)$$

for vertical rectangles.

The contour map of $\dfrac{z}{x^2 + z^2}$ shown in Figure 27-13 is used as in the case where H_z was computed for the infinite horizontal cylinder.

Field Component of Vertical Cylinder Measured by Airborne Magnetometer

As before let (a,β,γ) be the direction cosines of a line in the direction of which the field H_s is to be computed. The z axis is taken vertically downward as usual but the x and y axes are turned so that the y axis is perpendicular to the direction of H_s. The direction cosine β is therefore zero and H_s may be computed from

$$H_s = aH_x + \gamma H_z$$

as in the case of the horizontal cylinder. For the special case in which $a = l$, $\beta = m$, $\gamma = n$, that is, the case where the magnetization I is in the direction of the earth's field

$$H_s = lH_x + nH_z$$

To find H_x for the prism having the cross section shown in Figure 27-7 we start with the potential

$$V(x, y, z) = I \int\int\int_h^\infty \left[l \frac{\partial}{\partial u}\left(\frac{1}{r}\right) + n \frac{\partial}{\partial w}\left(\frac{1}{r}\right) \right] du\,dv\,dw \qquad (56)$$

which becomes, after carrying out the integration with respect to w,

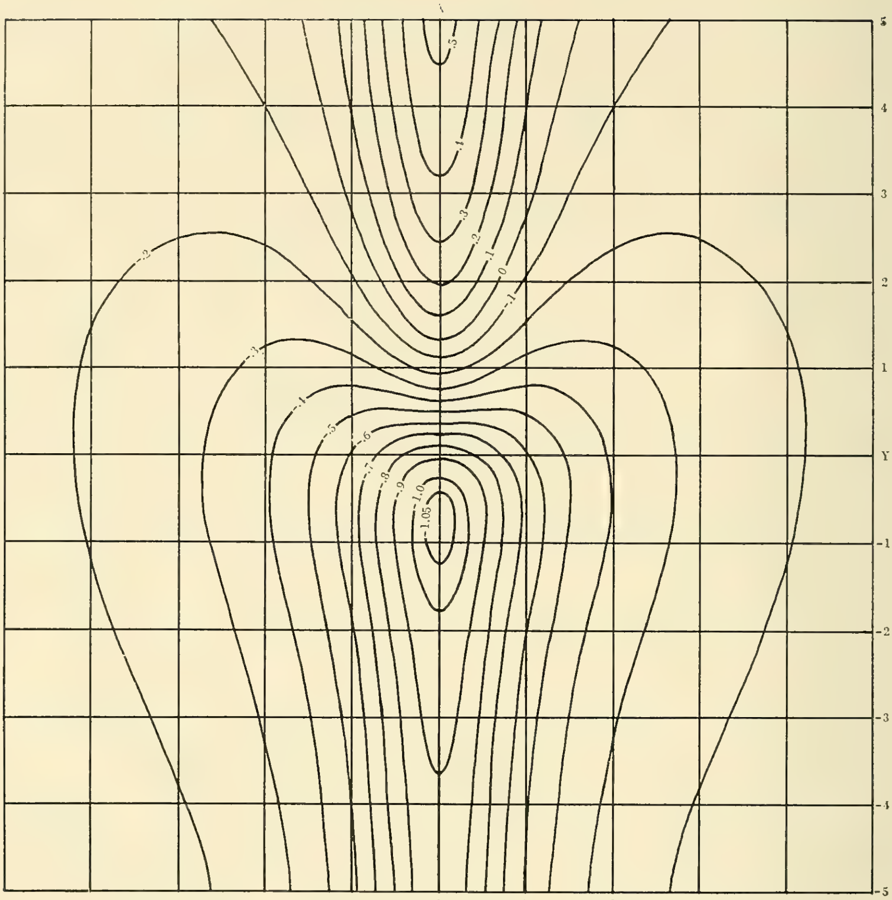


FIGURE 27-15. Contour map of the function given in formula (59).

$$V(x, y, z) = I \int\!\!\int \left\{ \frac{l(x-u)}{(x-u)^2 + (y-v)^2} + \frac{l(x-u)\ (z-h)}{[(x-u)^2 + (y-v)^2]\ [(x-u)^2 + (y-v)^2 + (z-h)^2]^{1/2}} - \frac{n}{[(x-u)^2 + (y-v)^2 + (z-h)^2]^{1/2}} \right\} du dv \tag{57}$$

If we now compute lH_x at the point (o,o,o), measuring x and y in units of h, we get the approximation

$$lH_x = I\left\{\frac{l^2x_2}{(x_2^2+y_3^2)\,(x_2^2+y_3^2+1)^{1/2}} - \frac{l^2x_2}{(x_2^2+y_3^2)} - \frac{ln}{(x_2^2+y_3^2+1)^{1/2}}\right\}(y_2-y_1)$$

$$-I\left\{\frac{l^2x_1}{(x_1^2+y_3^2)\,(x_1^2+y_3^2+1)^{1/2}} - \frac{l^2x_1}{(x_1^2+y_3^2)} - \frac{ln}{(x_1^2+y_3^2+1)^{1/2}}\right\}(y_2-y_1) \qquad (58)$$

Using H_z given by formula (51) we have for H_s

$$lH_x + nH_z = I\left\{\frac{l^2x_2}{(x_2^2+y_3^2)\,(x_2^2+y_3^2+1)^{1/2}} - \frac{l^2x_2}{(x_2^2+y_3^2)} - \frac{2ln}{(x_2^2+y_3^2+1)^{1/2}} + \frac{n^2x_2}{(y_3^2+1)\,(x_2^2+y_3^2+1)^{1/2}}\right\}(y_2-y_1)$$

$$-I\left\{\begin{matrix}\textit{same expression with } x_2\\ \textit{replaced by } x_1\end{matrix}\right\}(y_2-y_1) \qquad (59)$$

The expression $g(x,y)$ to be mapped is either of those within the brackets with the subscripts omitted. A map for the case of **I** inclined 60° may be plotted from the values given in Tables 27-IX. Such a map is shown in Figure. 27-15.

TABLE 27-I

r	$\log r^2$	r	$\log r^2$	r	$\log r^2$	r	$\log r^2$
1.00	0.00	3.32	2.40	11.02	4.80	36.60	7.20
1.05	0.10	3.49	2.50	11.59	4.90	38.47	7.30
1.11	0.20	3.67	2.60	12.18	5.00	40.45	7.40
1.16	0.30	3.86	2.70	12.81	5.10	42.52	7.50
1.22	0.40	4.06	2.80	13.46	5.20	44.70	7.60
1.28	0.05	4.26	2.90	14.15	5.30	46.99	7.70
1.35	0.60	4.48	3.00	14.88	5.40	49.40	7.80
1.42	0.70	4.71	3.10	15.64	5.50	51.94	7.90
1.49	0.80	4.95	3.20	16.44	5.60	54.60	8.00
1.57	0.90	5.21	3.30	17.29	5.70	57.40	8.10
1.65	1.00	5.47	3.40	18.17	5.80	60.34	8.20
1.73	1.10	5.75	3.50	19.11	5.90	63.43	8.30
1.82	1.20	6.05	3.60	20.09	6.00	66.69	8.40
1.92	1.30	6.36	3.70	21.12	6.10	70.11	8.50
2.01	1.40	6.69	3.80	22.20	6.20	73.70	8.60
2.12	1.50	7.03	3.90	23.34	6.30	77.48	8.70
2.23	1.60	7.39	4.00	24.53	6.40	81.85	8.80
2.34	1.70	7.77	4.10	25.79	6.50	85.63	8.90
2.46	1.80	8.17	4.20	27.11	6.60	90.02	9.00
2.59	1.90	8.58	4.30	28.50	6.70	94.63	9.10
2.72	2.00	9.03	4.40	29.96	6.80	99.48	9.20
2.86	2.10	9.49	4.50	31.50	6.90		
3.00	2.20	9.97	4.60	33.12	7.00		
3.16	2.30	10.49	4.70	34.81	7.10		

TABLE 27-II

	c=.1	c=.2	c=.3	c=.4	c=.5	c=.6	c=.7	c=.8	c=.9	c=1.0
y	x	x	x	x	x	x	x	x	x	x
0	0.10	0.20	0.31	0.41	0.52	0.64	0.76	0.89	1.03	1.18
.1	0.09	0.20	0.30							
.2	0.08	0.19	0.29	0.40	0.51					
.25						0.62	0.74	0.87	1.01	1.16
.3	0.06	0.16	0.27							
.4	0.03	0.14	0.25	0.36	0.47					
.5		0.10	0.21			0.57	0.70	0.83	0.98	1.13
.6		0.05	0.17	0.29	0.41					
.7			0.12							
.75						0.47	0.61	0.76	0.91	1.07
.8			0.07	0.20	0.33					
.9			0.00							
1.0				0.08	0.22	0.36	0.51	0.66	0.82	0.99
1.25						0.21	0.37	0.54	0.71	0.88
1.5						0.02	0.20	0.38	0.57	0.76
1.75								0.20	0.40	0.61
2.0									0.21	0.44
2.25										0.24
2.5										0.03

TABLE 27-III

	c=1.1	c=1.2	c=1.3	c=1.4	c=1.5	c=1.6	c=1.7	c=1.8	c=1.9	c=2.0
y	x	x	x	x	x	x	x	x	x	x
0	1.34	1.51	1.70	1.90	2.11	2.38	2.65	2.94	3.27	3.63
0.5	1.29	1.47	1.66	1.87	2.08	2.35	2.62	2.92		
1.0	1.17	1.36	1.56	1.78	1.99	2.27	2.55	2.86	3.19	3.56
1.5	0.96	1.17	1.39	1.63	1.85	2.15	2.44	2.76		
2.0	0.67	0.91	1.15	1.41	1.66	1.97	2.28	2.61	2.96	3.36
2.5	0.30	0.57	0.85	1.13	1.40	1.74	2.07	2.43		
3.0		0.15	0.47	0.79	1.09	1.47	1.82	2.20	2.60	3.02
3.5				0.39	0.73	1.14	1.53	1.93		
4.0					0.30	0.76	1.18	1.62	2.07	2.54
4.5						0.33	0.80	1.27		
5.0							0.36	0.88	1.40	1.99
5.5								0.44		
6.0									0.56	1.19
6.5										
7.0										0.31

TABLE 27-IV

	c=2.1	c=2.2	c=2.3	c=2.4	c=2.5	c=2.6	c=2.7	c=2.8	c=2.9	c=3.0
y	x	x	x	x	x	x	x	x	x	x
0	4.02	4.46	4.94	5.47	6.05	6.69	7.41	8.19	9.06	10.02
1	3.97	4.40	4.89	5.42	6.01	6.66	7.37	8.16	9.03	9.99
2	3.78	4.24	4.74	5.28	5.89	6.55	7.27	8.07	8.95	9.92
3	3.47	3.96	4.49	5.06	5.68	6.36	7.10	7.92	8.81	9.79
4	3.04	3.57	4.13	4.74	5.40	6.10	6.87	7.71	8.62	9.62
5	2.49	3.07	3.68	4.33	5.02	5.77	6.57	7.43	8.37	9.40
6	1.82	2.46	3.13	3.83	4.57	5.36	6.20	7.10	8.07	9.12
7	1.02	1.74	2.48	3.24	4.04	4.88	5.76	6.70	7.71	8.80
8	0.10	0.91	1.73	2.56	3.42	4.32	5.26	6.25	7.30	8.42
9			0.88	1.79	2.73	3.79	4.68	5.73	6.83	8.00
10				0.93	1.95	2.98	4.05	5.15	6.31	7.53

TABLE 27-V

c	.1	.2	.3	.4	.5	.6	.7	.8	.9	1
y	.46	.70	.90	1.11	1.31	1.52	1.75	1.99	2.25	2.53
c	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2
y	2.83	3.17	3.43	3.93	4.36	4.85	5.38	5.97	6.51	7.32
c	2.1	2.2	2.3							
y	8.10	8.97	9.82							

TABLE 27-VI

c=.1		c=.2		c=.3		c=.4		c=.5	
y	x	y	x	y	x	y	x	y	x
0	.101	0	.202	0	.315	0	.436	0	.577
.1	.102	.1	.207	.1	.320	.05	.438	.05	.580
.2	.107	.2	.217	.2	.335	.1	.444	.1	.588
.3	.115	.3	.233	.3	.361	.15	.453	.15	.601
.4	.126	.4	.257	.4	.400	.2	.466	.2	.621
.5	.141	.5	.289	.5	.452	.25	.484	.25	.646
.6	.160	.6	.330	.6	.521	.3	.505	.3	.678
.7	.184	.7	.381	.7	.610	.35	.532	.35	.719
.8	.213	.8	.445	.8	.724	.4	.564	.4	.767
.9	.248	.9	.522	.9	.870	.45	.602	.45	.825
1.0	.289	1.0	.617	1.0	1.061	.5	.645	.5	.895
1.1	.337	1.1	.733	1.1	1.317	.55	.696	.55	.979
1.2	.393	1.2	.873	1.2	1.678	.6	.756	.6	1.082
1.3	.458	1.3	1.047	1.25	1.925	.65	.826	.65	1.208
1.4	.533	1.4	1.264	1.3	2.241	.7	.906	.7	1.363
1.5	.620	1.45	1.394	1.35	2.676	.75	1.002	.75	1.566
1.6	.719	1.5	1.542	1.4	3.322	.8	1.113	.8	1.834
1.7	.833	1.55	1.725	1.41	3.496	.85	1.249	.82	1.970
1.8	.964	1.6	1.913	1.42	3.690	.9	1.412	.84	2.120
1.9	1.115	1.65	2.152	1.43	3.918	.95	1.619	.86	2.328
2.0	1.291	1.7	2.442	1.44	4.182	1	1.886	.88	2.559
2.1	1.529	1.75	2.810	1.45	4.490	1.02	2.016	.9	2.862
2.2	1.739	1.8	3.295	1.46	4.857	1.04	2.171	.91	3.046
2.3	2.029	1.82	3.537	1.47	5.313	1.06	2.347	.92	3.259
2.4	2.385	1.84	3.826	1.48		1.08	2.554	.93	3.527
2.45	2.596	1.86	4.167			1.1	2.811	.94	3.853
2.5	2.834	1.88	4.580			1.12	3.129	.95	4.267
2.55	3.109	1.90	5.113			1.14	3.560	.96	4.818
2.6	3.427					1.16	4.160		
2.65	3.807					1.18	4.830		
2.66	3.891								
2.67	3.980								
2.68	4.071								
2.69	4.168								
2.70	4.267								
2.71	4.373								
2.72	4.483								
2.73	4.600								
2.74	4.723								
2.75	4.852								

TABLE 27-VI Continued

c=.6		c=.7		c=.8		c=.9	
y	x	y	x	y	x	y	x
0	.750	0	.98	0	1.33	0	2.06
.05	.754	.05	.99	.02	1.34	.02	2.07
.1	.766	.1	1.01	.04	1.34	.04	2.08
.15	.786	.15	1.04	.06	1.35	.06	2.11
.2	.814	.2	1.08	.08	1.36	.08	2.14
.25	.853	.22	1.11	.1	1.38	.1	2.19
3	.902	.24	1.13	.12	1.40	.12	2.25
.35	.965	.26	1.16	.14	1.42	.14	2.33
.4	1.04	.28	1.20	.16	1.45	.16	2.43
.45	1.14	.3	1.23	.18	1.49	.18	2.55
.5	1.27	.32	1.27	.2	1.53	.2	2.71
.55	1.43	.34	1.32	.22	1.58	.21	2.81
.6	1.65	.36	1.37	.24	1.63	.22	2.92
.62	1.75	.38	1.43	.26	1.70	.23	3.04
.64	1.88	.4	1.50	.28	1.77	.24	3.19
.66	2.03	.42	1.57	.3	1.86	.25	3.37
.68	2.21	.44	1.66	.32	1.96	.26	3.58
.7	2.43	.46	1.76	.34	2.09	.27	3.85
.71	2.57	.48	1.88	.36	2.24	.28	4.18
.72	2.72	.5	2.02	.38	2.44	.29	4.64
.73	2.90	.52	2.19	.4	2.68	.30	5.28
.74	3.12	.54	2.41	.41	2.84		
.75	3.25	.55	2.54	.42	3.02		
.76	3.70	.56	2.69	.43	3.24		
.77	4.10	.57	2.86	.44	3.51		
.78	4.65	.58	3.05	.45	3.86		
.79	5.53	.59	3.31	.46	4.34		
		.6	3.63	.47	5.03		
		.61	4.04				
		.62	4.60				
		.63	5.53				

TABLE 27-VII

$\frac{z}{x^2+z^2}$	R	$\frac{z}{x^2+z^2}$	R	$\frac{z}{x^2+z^2}$	R
.050	10	.200	2.50	.42	1.190
.055	9.09	.205	2.44	.44	1.136
.060	8.33	.210	2.38	.46	1.087
.065	7.69	.215	2.33	.48	1.042
.070	7.14	.220	2.27	.50	1.000
.075	6.67	.225	2.22	.52	.962
.080	6.25	.230	2.17	.54	.927
.085	5.88	.235	2.13	.56	.893
.090	5.56	.240	2.08	.58	.862
.095	5.26	2.45	2.04	.60	.833
.100	5.00	.250	2.00	.62	.806
.105	4.76	.255	1.96	.64	.781
.110	4.55	.260	1.92	.66	.758
.115	4.35	.265	1.89	.68	.735
.120	4.17	.270	1.85	.70	.714
.125	4.00	.275	1.82	.72	.694
.130	3.85	.280	1.79	.74	.676
.135	3.70	.285	1.75	.76	.658
.140	3.57	.290	1.72	.78	.641
.145	3.45	.300	1.67	.80	.625
.150	3.33	.310	1.61	.82	.610
.155	3.23	.320	1.56	.84	.595
.160	3.12	.330	1.52	.86	.581
.165	3.03	.340	1.47	.88	.568
.170	2.94	.350	1.43	.90	.556
.175	2.86	.360	1.39	.92	.543
.180	2.78	.370	1.35	.94	.532
.185	.270	.380	1.32	.96	.521
.190	2.63	.390	1.28	.98	.510
.195	2.56	.400	1.25	1.00	.500

TABLE 27-VIII

x	5.0	4.5	4.0	3.5	3.0	2.8	2.6	2.4	2.2
$f(x,y)$	y	y	y	y	y	y	y	y	y
.75	.03								
.70	.25	.21	.15						
.65	.36	.33	.29	.23	.12				
.60	.46	.43	.40	.35	.28	.24	.19	.10	
.55	.55	.52	.48	.45	.39	.36	.33	.27	.20
.50	.64	.62	.58	.54	.48	.46	.42	.38	.32
.45	.74	.71	.67	.63	.58	.55	.52	.48	.43
.40	.83	.80	.77	.73	.67	.64	.61	.57	.52
.35	.94	.91	.87	.82	.76	.74	.71	.67	.62
.30	1.06	1.01	.98	.92	.86	.84	.80	.77	.71
.25	1.18	1.15	1.10	1.05	.98	.94	.91	.87	.82
.20	1.34	1.30	1.24	1.18	1.10	1.07	1.02	.98	.94
.15	1.52	1.47	1.42	1.34	1.25	1.21	1.16	1.12	1.06
.10	1.78	1.71	1.64	1.54	1.44	1.39	1.34	1.27	1.21
.05	2.14	2.14	1.94	1.82	1.68	1.63	1.55	1.48	1.40
0	2.77	2.60	2.44	2.25	2.05	1.97	1.87	1.78	1.68
—.05		4.78	3.88	3.31	2.83	2.68	2.51	2.32	2.15

TABLE 27-VIII Continued

x	2.0	1.8	1.6	1.4	1.2	1.0	.8	.6	.4
$f(x,y)$	y	y	y	y	y	y	y	y	y
.50	.26	.12							
.45	.38	.29	.16						
.40	.47	.40	.31	.13					
.35	.57	.51	.42	.31					
.30	.66	.61	.52	.42	.25				
.25	.77	.71	.62	.52	.39	.11			
.20	.88	.81	.72	.63	.51	.30			
.15	.99	.93	.84	.74	.62	.45	0		
.10	1.14	1.06	.97	.87	.73	.57	.30		
.05	1.33	1.23	1.13	1.01	.88	.71	.46		
0	1.57	1.45	1.34	1.19	1.04	.86	.62	.20	
—.05	1.99	1.82	1.64	1.47	1.26	1.05	.80	.43	
—.10			2.60	2.06	1.68	1.36	1.04	.65	
—.10			3.50	3.86	4.10	4.30	4.50	4.60	4.76
—.15							1.66	.95	.17
—.15							2.20	2.67	2.90
—.20									.61
—.20									1.79

TABLE 27-VIII Continued

x	.2	0	—.2	—.4	—.6	—.8	—1.0	—1.2	—1.4
$f(x,y)$	y	y	y	y	y	y	y	y	y
—.10	4.85	4.92	4.98	5.00					
—.15	3.05	3.17	3.28	3.34	3.43	3.47	3.51	3.52	3.55
—.20	2.10	2.29	2.43	2.52	2.59	2.64	2.68	2.71	2.72
—.25	1.46	1.73	1.89	2.00	2.09	2.14	2.19	2.20	2.22
—.30	.86	1.34	1.54	1.65	1.74	1.80	1.85	1.87	1.88
—.35		1.00	1.26	1.39	1.49	1.56	1.59	1.62	1.64
—.40		.75	1.04	1.19	1.29	1.36	1.39	1.42	1.44
—.45		.48	.86	1.02	1.13	1.21	1.23	1.26	1.26
—.50		0	.70	.88	.98	1.06	1.10	1.12	1.13
—.55			.53	.76	.87	.93	.98	1.00	1.01
—.60			.37	.63	.76	.82	.87	.90	.91
—.65			.14	.51	.67	.73	.77	.80	.81
—.70				.39	.54	.63	.68	.70	.72
—.75				.26	.44	.53	.58	.61	.62
—.80					.32	.44	.49	.52	.54
—.85					.18	.34	.39	.43	.44
—.90						.20	.29	.33	.35
—.95							.14	.21	.24

TABLE 27-VIII Continued

x	—1.6	—1.8	—2.0	—2.2	—2.4	—2.8	—3.0	—3.5	—4.0
$f(x,y)$	y	y	y	y	y	y	y	y	y
—.10								5.00	4.90
—.15	3.53	3.53	3.54	3.52	3.53	3.49	3.44	3.38	3.30
—.20	2.74	2.73	2.73	2.73	2.70	2.68	2.64	2.58	2.54
—.25	2.24	2.23	2.23	2.22	2.22	2.18	2.16	2.12	2.07
—.30	1.89	1.90	1.90	1.88	1.87	1.85	1.84	1.80	1.76
—.35	1.64	1.64	1.64	1.63	1.62	1.60	1.59	1.56	1.53
—.40	1.45	1.44	1.44	1.44	1.42	1.40	1.40	1.37	1.34
—.45	1.27	1.28	1.28	1.28	1.27	1.24	1.24	1.21	1.19
—.50	1.15	1.14	1.15	1.13	1.12	1.10	1.10	1.08	1.06
—.55	1.02	1.02	1.02	1.01	1.01	.99	.98	.96	.94
—.60	.92	.92	.90	.91	.90	.88	.87	.86	.84
—.65	.83	.81	.81	.80	.80	.79	.78	.76	.74
—.70	.74	.72	.72	.72	.71	.70	.68	.68	.66
—.75	.64	.63	.63	.62	.62	.60	.60	.58	.56
—.80	.54	.54	.54	.53	.53	.52	.51	.50	.48
—.85	.46	.45	.46	.44	.44	.42	.42	.40	.38
—.90	.35	.35	.35	.35	.34	.32	.32	.29	.27
—.95	.24	.24	.24	.23	.22	.20	.18	.16	.12
—1.00		0							

TABLE 27-VIII Continued

	$x=—4.5$	$x=—5$	$y=0$	$y=.2$	$y=.4$	$y=.6$	$y=.8$	$y=1$	$y=1.2$
$f(x,y)$	y	y	x	x	x	x	x	x	x
.75			4.96						
.70			3.60						
.65			2.84						
.60			2.34						
.55			1.99						
.50			1.74	1.89					
.45			1.53	1.64					
.40			1.36	1.45					
.35			1.21	1.29					
.30			1.09	1.16					
.25			.98	1.04					
.20			.89	.92	1.07				
.15			.80	.84	.96				
.10			.72	.75	.86				
.05			.65	.69	.76				
0			.57	.60	.67	.78			
—.05			.51	.55	.58	.68			
—.10	4.77	4.63	.45	.47	.51	.58			
—.15	3.20	3.13	.39	.40	.43	.49	.55		
—.20	2.47	2.42	.34	.34	.36	.40	.44	.47	.49
—.25	2.04	1.99	.28	.28	.29	.31	.32	.32	.08
—.30	1.73	1.70	.22	.22	.22	.22	.21	.17	
—.35	1.50	1.48	.16	.16	.16	.14	.09		
—.40	1.32	1.30	.12	.10	.08	.05			
—.45	1.16	1.15	.06	.05	0	—.04			
—.50	1.04	1.02	0	—.02	—.07	—.14			
—.55	.92	.91	—.06	—.08	—.14				
—.60	.82	.81	—.12	—.14	—.22				
—.65	.73	.72	—.18	—.21	—.31				
—.70	.64	.64	—.25	—.28					
—.75	.54	.54	—.33	—.36					
—.80	.47	.46	—.42	—.47					
—.85	.37	.36	—.53	—.62					
—.90	.26	.24	—.68						
—.95	.04		—.90						
—1.00			—1.80						
—.95			—4.80						

TABLE 27-IX

$y=0$		$y=.2$		$y=.4$		$y=.6$		$y=.8$	
x	$g(x,y)$	x	$g(x,y)$	x	$g(x,y)$	x	$g(x,y)$	x	$g(x,y)$
—3.69	—.90	—4.43	—.85	—3.61	—.80	—3.72	—.70	—3.86	—.60
—2.59	—.95	—2.99	—.90	—2.51	—.85	—2.56	—.75	—2.63	—.65
—1.86	—1.00	—2.13	—.95	—1.79	—.90	—1.80	—.80	—1.81	—.70
—1.27	—1.05	—1.50	—1.00	—1.15	—.95	—1.14	—.85	—1.10	—.75
—.45	—1.05	—.35	—1.00	—.48	—.95	—.44	—.85	—.40	—.75
—.28	—1.00	—.20	—.95	—.24	—.90	—.17	—.80	—.10	—.70
—.15	—.95	—.10	—.90	—.10	—.85	—.03	—.75	—.08	—.65
—.04	—.90	—.01	—.85	.01	—.80	.10	—.70	.24	—.60
.02	—.85	.07	—.80	.10	—.75	.22	—.65	.37	—.55
.09	—.80	.15	—.75	.19	—.70	.32	—.60	.50	—.50
.16	—.75	.23	—.70	.27	—.65	.42	—.55	.64	—.45
.21	—.70	.30	—.65	.35	—.60	.52	—.50	.76	—.40
.30	—.65	.37	—.60	.42	—.55	.62	—.45	.89	—.35
.36	—.60	.44	—.55	.51	—.50	.72	—.40	1.03	—.30
.43	—.55	.50	—.50	.59	—.45	.82	—.35	1.18	—.25
.49	—.50	.57	—.45	.68	—.40	.93	—.30	1.34	—.20
.56	—.45	.64	—.40	.76	—.35	1.05	—.25	1.52	—.15
.62	—.40	.71	—.35	.84	—.30	1.17	—.20	1.72	—.10
.69	—.35	.79	—.30	.94	—.25	1.31	—.15	1.96	—.05
.76	—.30	.87	—.25	1.04	—.20	1.46	—.10	2.25	0
.84	—.25	.96	—.20	1.15	—.15	1.64	—.05	2.58	.05
.92	—.20	1.04	—.15	1.27	—.10	1.84	0	2.98	.10
1.01	—.15	1.15	—.10	1.40	—.05	2.06	.05	3.53	.15
1.11	—.10	1.26	—.05	1.55	0	2.33	.10	4.28	.20
1.20	—.05	1.38	0	1.72	.05	2.68	.15		
1.32	0	1.52	.05	1.91	.10	3.10	.20		
1.45	.05	1.67	.10	2.14	.15	3.64	.25		
1.59	.10	1.85	.15	2.42	.20	4.39	.30		
1.76	.15	2.05	.20	2.74	.25				
1.94	.20	2.29	.25	3.18	.30				
2.16	.25	2.60	.30	3.74	.35				
2.42	.30	2.97	.35	4.55	.40				
2.76	.35	3.45	.40						
3.18	.40	4.13	.45						
3.74	.45								
4.48	.50								

TABLE 27-IX Continued

$y=1$		$y=1.2$		$y=1.4$		$y=1.6$		$y=1.8$	
x	$g(x,y)$	x	$g(x,y)$	x	$g(x,y)$	x	$g(x,y)$	x	$g(x,y)$
—4.50	—.50	—3.78	—.45	—3.60	—.40	—3.79	—.35	—4.40	—.30
—3.95	—.55	—2.51	—.50	—2.35	—.45	—2.42	—.40	—2.70	—.35
—3.02	—.60	—1.63	—.55	—1.41	—.50	—1.40	—.45	—1.55	—.40
—1.25	—.65	—.70	—.60	.04	—.50	.13	—.45	.33	—.40
—.24	—.65	.03	—.55	.40	—.45	.59	—.40	.86	—.35
.06	—.60	.32	—.50	.72	—.40	.95	—.35	1.30	—.30
.27	—.55	.56	—.45	1.01	—.35	1.32	—.30	1.74	—.25
.45	—.50	.80	—.40	1.28	—.30	1.68	—.25	2.24	—.20
.62	—.45	1.00	—.35	1.57	—.25	2.09	—.20	2.82	—.15
.78	—.40	1.22	—.30	1.91	—.20	2.57	—.15	3.55	—.10
.95	—.35	1.46	—.25	2.30	—.15	3.16	—.10	4.53	—.05
1.13	—.30	1.73	—.20	2.77	—.10	3.93	—.05		
1.32	—.25	2.04	—.15	3.36	—.05				
1.53	—.20	2.39	—.10	4.16	0				
1.76	—.15	2.84	—.05						
2.04	—.10	3.40	0						
2.36	—.05	4.16	.05						
2.76	0								
3.26	.05								
3.93	.10								
4.88	.15								

TABLE 27-IX Continued

$y=2$ x	$g(x,y)$	$y=2.2$ x	$g(x,y)$	$y=2.4$ x	$g(x,y)$	$y=2.6$ x	$g(x,y)$	$y=2.8$ x	$g(x,y)$
—3.30	—.30	—4.34	—.25	—3.43	—.25	—2.86	—.25	—4.35	—.20
—1.91	—.35	—2.54	—.30	—1.87	—.30	—1.15	—.30	—2.28	—.25
.65	—.35	—1.14	—.35	.92	—.30	.50	—.30	1.42	—.25
1.23	—.30	.27	—.35	1.74	—.25	1.61	—.25	2.54	—.20
1.78	—.25	1.11	—.30	2.52	—.20	2.53	—.20	3.68	—.15
2.36	—.20	1.78	—.25	3.44	—.15	3.58	—.15		
3.03	—.15	2.44	—.20	4.67	—.10	4.95	—.10		
3.90	—.10	3.26	—.15						
		4.32	—.10						

$y=3.0$ x	$g(x,y)$	$y=3.5$ x	$g(x,y)$	$y=4$ x	$g(x,y)$	$y=5$ x	$g(x,y)$
—3.8	—.20	—2.6	—.20	—4.36	—.15	—2.40	—.15
—1.73	—.25	2.17	—.20	—1.20	—.20	3.00	—.15
1.20	—.25	3.85	—.15	1.40	—.20		
2.48	—.20			3.85	—.15		
3.85	—.15						

TABLE 27-IX Continued

$g(x,y)$	$x=5$ y	$x=4$ y	$x=3$ y	$x=2$ y	$x=1$ y	$x=0$ y	$x=-1$ y	$x=-2$ y	$x=-3$ y	$x=-4$ y	$x=-5$ y
.50	.18										
.45	.34	.15									
.40	.45	.31									
.35	.56	.44	.21								
.30	.66	.54	.36								
.25	.76	.65	.47								
.20	.88	.76	.57	.14							
.15	1.01	.89	.69	.31							
.10	1.16	1.02	.82	.46							
.05	1.34	1.17	.93	.58							
0	1.59	1.36	1.09	.69							
—.05	1.95	1.61	1.26	.83							
—.10	2.62	2.03	1.51	.98							
—.15			1.96	1.18							
—.15			5.00						4.75	4.16	3.75
—.20				1.50	.32						
—.20				3.65	4.12	4.20	4.06	3.74	3.34	2.92	2.64
—.25					.52						
—.25					3.12	3.32	3.23	2.90	2.55	2.27	2.06
—.30					.74						
—.30					2.31	2.70	2.64	2.36	2.07	1.87	1.71
—.35					1.35	2.26	2.23	1.98	1.73	1.58	1.47
—.40						1.92	1.92	1.69	1.49	1.37	1.27
—.45						1.65	1.67	1.47	1.30	1.18	1.11
—.50						1.41	1.48	1.29	1.13	1.04	.97
—.55						1.21	1.31	1.13	.99	.91	.85
—.60						1.04	1.16	1.00	.86	.79	.74
—.65						.87	1.03	.88	.75	.68	.63
—.70						.73	.92	.76	.65	.58	.53
—.75						.57	.81	.66	.55	.48	.42
—.80						.41	.70	.57	.45	.37	.32
—.85						.19	.61	.47	.34	.24	.13
—.90							.52	.36	.20		
—.95							.42	.24			
—1.00							.22				

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Chapter 28 GEOCHEMICAL PROSPECTING

Harold Bloom

The geochemical method of prospecting for petroleum has been based primarily on the premise that buried oil and gas accumulations emanate gaseous hydrocarbons which migrate to the earth's surface. In the early days of exploration, visible oil and gas seeps were often the only clues that led to the drilling and discovery of oil and gas fields. In the Gulf Coast salt-dome province, for example, 35 of 141 salt domes discovered before 1936 were detected visually (Sawtelle, 1936). As visible clues became less conspicuous, it became necessary to develop techniques sufficiently sensitive to detect the ever-diminishing volume of gas or oil leakage. In a general way, it seems apparent that the amount of gas reaching the surface would depend upon the depth of the reservoir rock, the volume of gas present, the reservoir pressure, and the accessibility to the surface. Today, methods capable of measuring 1-part-per-billion of methane are used to identify surface hydrocarbons.

The mechanism of gas migration to the surface is not fully understood because many factors influence the flow of molecular gas: porosity and permeability of the strata, pressure gradient, temperature, and viscosity of the hydrocarbon are but a few of these factors. The subsurface fractures, faults, folds, and ground-water movements further complicate any analysis of gas movement.

Gaseous hydrocarbons conceivably could rise vertically from a pool to the surface if the subsurface pressure gradient is upward and if there were no aquifers with hydrodynamic gradients intervening between the pool and the surface. An aquifer above a pool would have to be saturated by the rising gases before they would be released for further upward migration. Waters contained in the shales or siltstones could similarly absorb rising gases. If the water should be flowing laterally in the formations between the pool and surface, and it were not gas saturated under the existing conditions of heat and pressure, then all gas entering the formation would be taken into solution and carried to a new position, perhaps considerably removed from the area of the pool. The fact that subsurface conditions generally are unknown to the prospector make interpretation of geochemical anomalies extremely difficult. For a particular exploration method to be acceptable, it must yield accurate information under most conditions. When the performance record of a technique or procedure is poor, it becomes uneconomical to use and is discarded. This seems to have been the fate of the early geochemical prospecting methods.

HISTORY

In the early 1930's, geochemical prospecting methods were first tried in an effort to reduce exploration costs, and by 1940 this form of prospecting reached a peak. From this date on, interest waned, and a search of the current literature reveals only an occasional paper published by commercial laboratories. In the past few years, however, research programs directed at the geochemistry of petroleum have been undertaken by some major oil companies.

A distinction should perhaps be drawn between geochemistry and geochemical prospecting. Geochemistry is a study of the basic chemistry of pertroleum and its derivatives, i.e., trace-metal associations, genesis, etc.—problems which may lead indirectly to the discovery of petroleum. Geochemical prospecting is the applied side of geochemistry—that which may be used in the direct discovery of petroleum. Information uncovered as a result of pure geochemical research may be expected to provide significant leads upon which future geochemical prospecting methods may be based.

Among the problems being investigated is a study of the composition and behavior of the organic components in rocks; such data might enable geologists to determine the source rocks of petroleum. A study of the formation of rocks may throw light upon the environments under which ancient oil-source rocks formed. Nickel and vanadium porphyrin compounds occur as trace metals in crude oils, and are being investigated from the viewpoint of learning the manner of petroleum migration as well as accumulation. While much of this research is long range, current information may assist the field geologist in his recommendations on favorable areas in which to prospect.

The Russians have had a coordinated research program in geochemical exploration since the 1930's, but because of the language barrier, it has been impossible to follow this program closely. A textbook, (Kartsev, et al., 1954), embodying much of this work is published in Russian for the college student. It is believed to be the only one available on this subject. Periodically, at national meetings, Russians in the field of geochemical exploration re-evaluate methods and plan future programs. At the Conference of Geochemical Prospecting for Petroleum and Gas held in Moscow, March 1955, the Russian geochemists (Kalinin, et al., 1955) noted their extremely unfavorable position with respect to the development of theoretical principles and with respect to the geochemical methods.

The geochemical methods that are briefly described in this paper are based upon the detection of some effect created by migrating gases of petroliferous origin.

SOIL-GAS METHOD In 1929, Laubmeyer (1933) conducted the first successful series of soil-gas studies. Known oil districts were investigated to determine whether gas leakages were higher than in adjoining non-petroliferous areas. To collect samples, he augered a hole from 3 to 6 feet deep and then sealed it for 24 to 48 hours. The gas filling the hole was removed for immediate analysis. Using portable analytical equipment, Laubmeyer brought the gas samples into contact with a heated platinum filament and burned it with air oxygen. The resulting heat of combustion increased the resistance of the platinum wire, the amount of which then was measured by means of a sensitive galvanometer. This method, designed to detect methane down to 1 part in 10^{10} parts of air, yielded results that showed hydrocarbons occurred in greater quantities over fields of known oil production than over barren areas. Laubmeyer's reliance on the detection of very low values of methane was found to be unwise, since such non-petroliferous sources of methane as lignites and coals also gave confusing anomalies.

The Russians became interested in soil-gas methods, and in 1932 Sokolov published the results of his investigations. Using a similar system of bore holes, he first reduced the hole pressure and then collected the gas sample by displacing water from a specially designed container. Methane and heavier hydrocarbons were separated by reducing the temperature to that of liquid oxygen (-183C). The lighter fraction, methane, remained gaseous while the heavier hydrocarbons condensed. A high ratio of light to heavy fraction was interpreted as being over a gas reservoir; a low ratio was indicative of being over an oil pool. This method of gas analysis characteristically showing high methane values to fall directly over the oil reservoir, confirmed Laubmeyer's findings. This type of anomaly is shown in Figure 28-1.

A disadvantage of this technique is the difficulty in obtaining usable samples from areas where ground water is near the surface or from hard rock, compact clays, and sand hills.

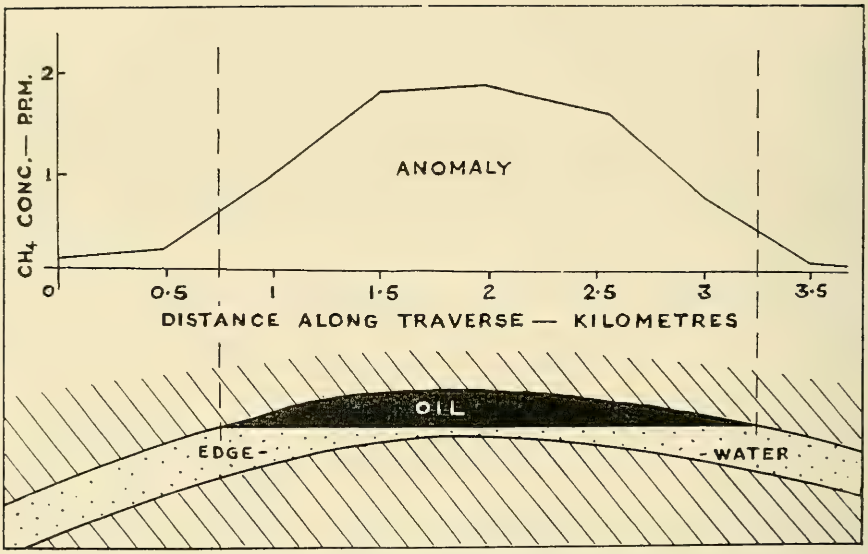

FIGURE 28-1. Soil-gas methods show methane concentrations directly over the oil pool. This diagram is a simplified form of such an occurance (Taylor).

Using a geodynamic method, Pirson (1941), measured gaseous emanations from the earth's surface. Recognizing the ethane content as the significant gas fraction, he recorded microleakage in cubic milliliters of sample collected over a 24-hour period.

The fact that the Russians were dissatisfied with the results of their soil-gas exploration methods was revealed recently (Kalinin, et al., 1955). Yet to be explained satisfactorily were some of the following disturbing questions: (1) Why had gas surveys in some areas failed to show positive anomalies over known fields: and, (2) why had other areas that indicated positive hydrocarbon anomalies failed to confirm the presence of gas or oil after drilling? An equally disquieting fact was that many of their previously existing gas anomalies had disappeared when supposedly improved pieces of apparatus (like the chromathermograph and others) were used to check these fields. Obviously, there is much more work to be done before gas surveys can be used with confidence.

GAS LOGGING

Gas analysis for determining the hydrocarbon content of muds and cores in well cuttings has had greater acceptance by the oil industry. This procedure (Mogilevski, 1938) has been found to reliably indicate favorable gas and oil accumulations before the drill reached the reservoir sands. The details of this operation are similar to geochemical logging.

SOIL METHOD

It was not until the late 1930's that Rosaire and Horvitz (1939) investigated the possibilities of extracting hydrocarbons from soil material, a process that differs from the soil-gas method in which the gas is drawn from the interstices of the soil. Rosaire and Horvitz learned that hydrocarbons were adsorbed or occluded by soils in amounts far greater than those that are detected by the gas technique, a fact which means that analytical techniques could be used whose sensitivities were considerably less than those used in soil-gas studies. In the soil method, sample collection was expedited, since water-logged terranes, and compact clays did not affect the quality of the sample. This new technique showed that ethane, propane, and higher hydrocarbons yielded more significant information than methane, because ethane, propane, and the higher hydrocarbons were derived more generally from petroleum, whereas methane could originate from decaying organic matter in soils.

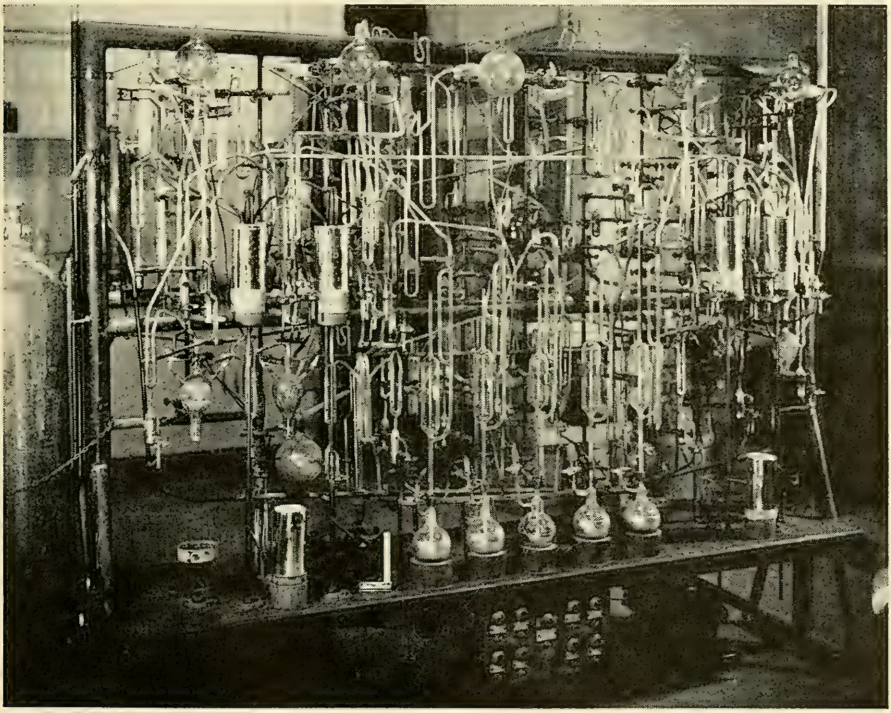

FIGURE 28-2. The laboratory set-up used by Horvitz to determine methane, ethane, and higher hydrocarbons entrained by soils.

A brief description of the Horvitz (1954) technique follows: Samples are collected by means of a hand auger or a mechanical drill from a depth of 8 to 12 feet, placed in a pint jar, sealed, and shipped to the laboratory. Broad reconnaissance surveys are carried out by taking samples at ¼ to ½ mile intervals. Samples found to be of interest indicate areas which then are sampled in a denser pattern.

A sample of about 100 grams is treated first in a partial vacuum with an aqueous solution of copper sulphate, then by phosphoric acid. The copper sulphate prevents the acid from reacting with the carbide chips from the auger,

FIGURE 28-3. Soil analysis for ethane and propane. Small symbols indicate wells drilled before and large symbols wells completed after the soil survey. Station interval is 500 feet. Production is from Miranda sand at 1500 feet (Horvitz).

which could produce spurious methane. The acid decomposes any carbonates present and facilitates the release of hydrocarbons. The carbon dioxide is removed with potassium hydroxide and the flask containing the sample then is heated for 30 minutes at 100C. This mild treatment does not decompose the included organic matter. The sample, now free of carbon dioxide, is collected in an evacuated tube and analyzed. After the gaseous extract is cleaned with potassium hydroxide solution, concentrated sulphuric acid, ascarite and phosphoric anhydride, the gas is separated into fractions of (1) methane, and (2) ethane and heavier hydrocarbons. Each fraction is analyzed separately. Liquid nitrogen (-196C) affects the separation, as methane remains gaseous while the ethane fraction condenses at this temperature. The amount of methane is de-

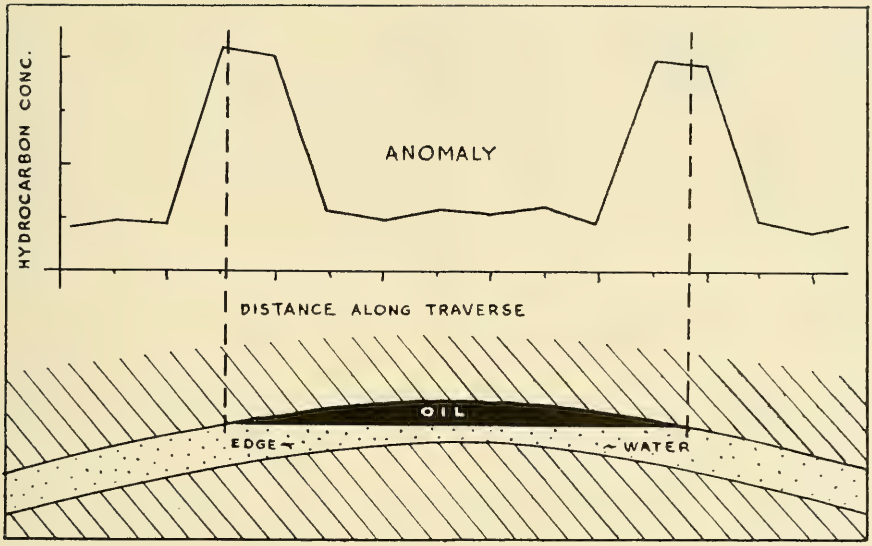

FIGURE 28-4. Analyses of the soil for entrained hydrocarbons shows the anomaly maximum to fall over the edges of the oil accumulation (Taylor).

termined by burning over a glowing platinum wire and then measuring the resulting carbon dioxide. Ethane and the heavier hydrocarbons are determined by first vaporizing and then measuring the volume of the condensed fraction. This fraction then is ignited, and the resulting carbon dioxide in the final volume is a measure of the quantity of ethane and heavier hydrocarbons initially present. Sensitive McLeod gauges are used to indicate the pressures from which the volume of hydrocarbons are calculated. After these volumes are converted to weights, on a dry basis, they are expressed finally in parts-per-billion of dry weight of the soil sample. A photo of the Horvitz laboratory setup is shown in Figure 28-2. The precision of this method is claimed to be within limits of 20 percent for values exceeding 10 parts-per-billion. Costs of a soil survey, according to Horvitz, are generally about one fourth that of a seismic survey.

An example of a soil survey showing ethane-propane values collected over a sand lens is shown in Figure 28-3. Note that the producing zone is limited to the low ethane-propane values which are bordered by higher concentrations.

Figure 28-4, a simplified drawing of a typical hydrocarbon anomaly, shows a maximum concentration around the edges of the oil accumulation. This differs from the halo obtained by soil-gas techniques (fig. 28-1), wherein the methane appears highest directly over the pool of oil. Rosaire (1938) explains these differences by assuming that the strata overlying the oil pool are made less permeable to migrating hydrocarbons because of the deposition of minerals from ground water during their upward migration. That such an area of induration exists may be shown by an inspection of drilling records made by fish-tail bits and light equipment in the Gulf Coast salt-dome area. The rate of penetration was lower over the domes than in the surrounding area. Others have postulated that cementation of strata above the structure could be effected by the reduction of calcium bicarbonate to insoluble calcium carbonate. The reduction was caused by the greater solubility of CO_2 in oil than in water. That sulfates were reduced to sulfides by bacteria has also been suggested.

GEOCHEMICAL LOGGING The chemical analysis of well cuttings for various hydrocarbons was undertaken by Horvitz (1949) to prove that surface soil anomalies were caused by the vertical migration of gaseous hydrocarbons from a deep source. Though continuous cores generally were not available, analysis of samples from many wells did suggest that such a relationship could exist. In the course of the investigation, it became apparent that evidences of oil and gas accumulations could be detected as much as 1000 feet above the source. These analytical results, which become available as the drilling progresses, serve to forewarn the driller of approaching potentially productive sands. Premature abandonment of drilling also is minimized.

Horvitz's scheme of sample collection consists of removing cuttings from the circulating drilling fluid at the end of each 30 feet of section drilled. After the samples are washed free of the fluid, they are sealed in jars and sent to the laboratory, where composite samples for each 90 feet of section are prepared for chemical analysis. When detailed information is required, a greater sampling density is used.

The chemical analysis method is the same as Horvitz uses for soil, except that a separate determination of the moisture content of the sample is made for the final calculations. The hydrocarbon data is plotted on a log to a scale of 1 inch = 1000 feet. Figure 28-5 shows the Danzig no. 1 well, in Rosenburg Field, Texas, which produced high-gravity oil (59° Bé) from a sand at 7736 to 7743 feet. Values for hydrogen and total hydrocarbons are shown in the first two columns. Methane, ethane, propane, butane, pentane, and heavier hydrocarbons do not show a decided increase until about 6000 feet, when approximately 5000 parts-per-billion is reached. Just above the producing sand a value of about 28,000 parts-per-billion is attained. The pressure of such a distribution of the heavier hydrocarbons is usually indicative of an accumulation of gas and distillate. Samples of nonproducing wells show neglible quantities of hydrocarbons. It has been noted, too, that longer sections of higher hydrocarbon content are obtained from wells located at the margins of petroleum accumulations than are obtained from wells in the center.

FLUOROANALYSIS

Liquid petroleum will fluoresce under ultraviolet light of wave lengths down to 2000 angstrom units (DeMent, 1947). This property of fluorescence has led to the development of analytical techniques which were applied to exploration by Blau (1943), Squires (1948), and others. Although sands, soils, shales, and drill cuttings may be analyzed rapidly for petroleum content, experience is necessary for interpretation of results.

Reconnaissance surveys are conducted on a grid pattern in much the same way that soil surveys are conducted. Samples of about 1 ounce are collected near surface, or at about 2 feet in depth, after which they are dried, crushed, and sieved prior to analysis. The fluorescence is recorded on a sensitive film from which differences of intensity are read by means of a densitometer. A sensitivity in the order of 1 part-per-billion is claimed, and many samples may be processed simultaneously.

Samples collected over barren areas would not be expected to fluoresce, whereas those that do would be related to gas seepage. Anomalous values are found over the accumulation as well as around the edges (Campbell, 1946). Satisfactory results are reported from surveys conducted in a variety of terranes, including swamps and sand dunes. The cost of a fluorographic survey, according to Turner (1943), is about $3.50 for each sample collected and analyzed.

FLUOROLOGS

Well cuttings can be screened for fluorescence in much the same manner as cuttings are analyzed by other geochemical procedures. Fluorologs, as they are called, make use of a photographic method for recording fluorescence. The data are plotted on standard log forms that show the depth at which the sample was collected.

The fluorolog of a producing well usually shows values that are relatively high at the surface and that progressively increase with depth. Dry holes generally have low readings throughout their entire length. Fluorologs, like geochemical well logs, provide a direct measurement of petroleum derivatives and can supplement electric-log data.

MICROBIOLOGICAL METHODS

Hydrocarbon gases from underlying oil and gas pools have been shown to sustain and stimulate the growth of certain microorganisms in surface soils. Some techniques are based upon the effects of gaseous hydrocarbons on certain bacteria, while others measure the effects of the bacteria upon these gases. Bacteria may be implanted in the soil and their development studied, or the soil can be analyzed for specific strains of bacteria.

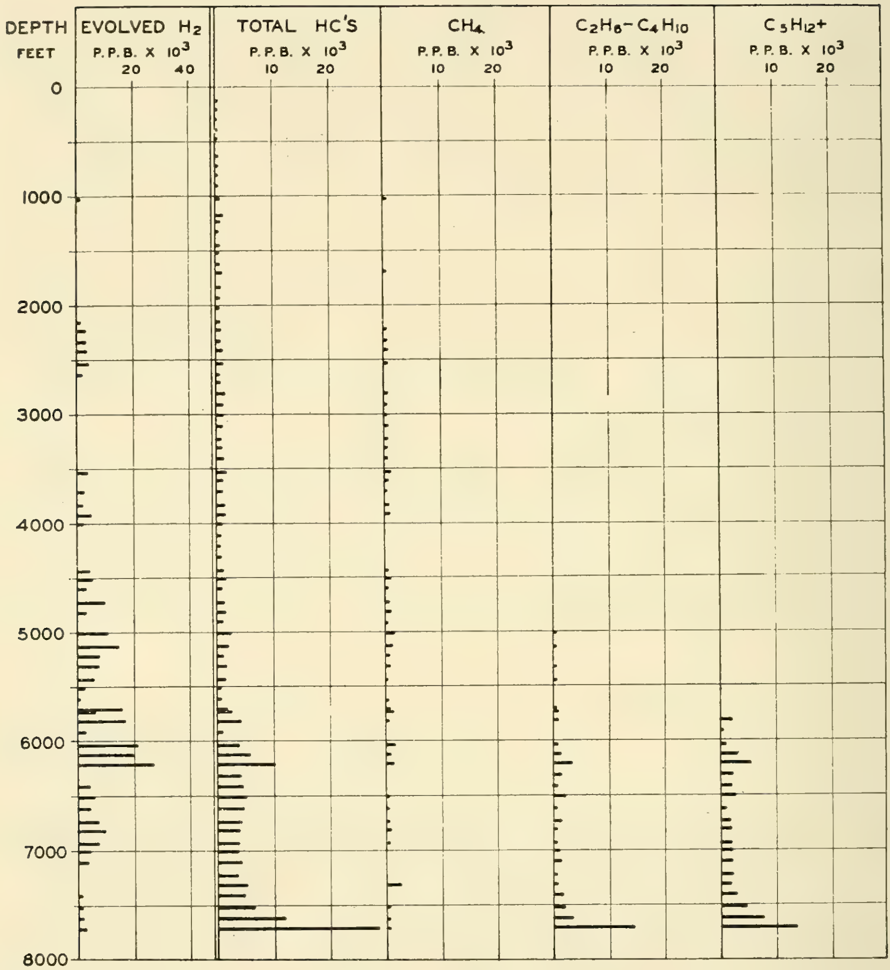

FIGURE 28-5. Geochemical log of the Danzig No. 1 well, Rosenberg field, Fort Bend County, Texas. This well is producing high gravity oil from 7736-43 feet (Horvitz).

Mogilevski (1940) showed that certain strains of bacteria are able to utilize gaseous hydrocarbons as their sole source of carbon and energy and are particularly abundant where they overlie oil and gas fields. Some successes have been reported by Subbota (1953), with this approach. In a review of a book by Mogilevski, he states that out of 20 microbiological anomalies, 16 fields were proved by subsequent drilling. Successful application also has been reported by Schwartz and Mueller (1948).

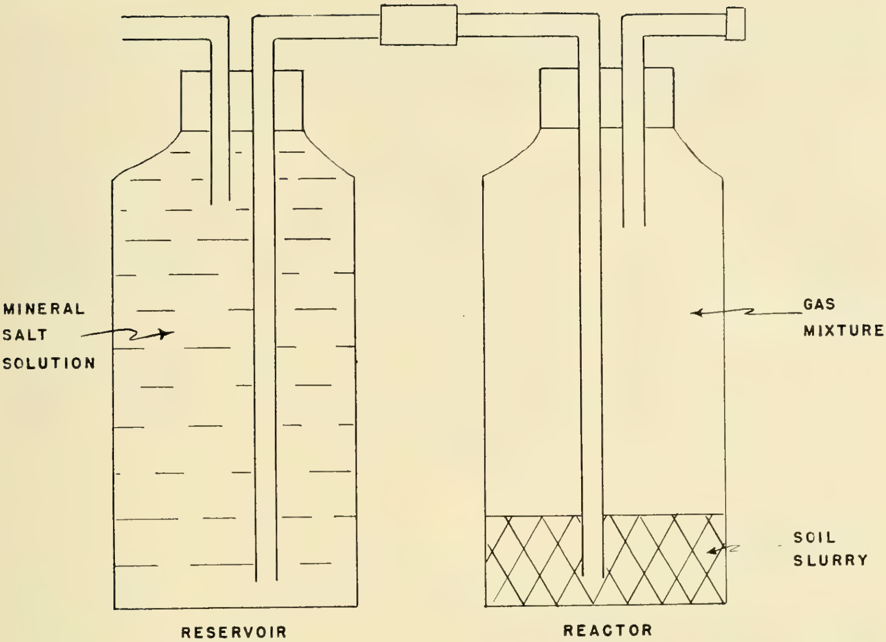

FIGURE 28-6. The simple apparatus shown here was used to incubate bacteria as a means of measuring their density in the soil (Stravinski).

In 1947 Bokova and others showed that certain strains of bacteria could oxidize methane, pentane, and hexane, but not ethane or propane. Ethane-oxidizing bacteria that were isolated could utilize propane, butane, and higher hydrocarbons. He was also able to stimulate selectively the growth of a given species by introducing a specific hydrocarbon gas into the circulating air current. Concentrations of 0.019 percent methane and 0.001 percent propane were found adequate to activate these bacteria strains.

Stravinski (1955) described a simple apparatus for measuring the hydrocarbon-consuming bacteria population. Soil samples were collected from about 24 inches in depth and about 25 feet apart. They were dried and sieved through a U. S. stainless-steel series No. 18 sieve. A nutrient media, consisting of 1.0 gram of NH_4NO_3, 0.5 gram of K_2HPO_4, and 0.1 gram of $CaSO_4$ was diluted with distilled water to 1 liter, with a resulting pH of 7.5. A pint of sample then was mixed for one minute with 700 milliliters of the nutrient media, after which a 50 milliliter slurry sample was transferred to a 250 milliliter reactor jar. This jar, meanwhile, was filled with a prepared gas mixture containing 65 percent hydrocarbon gas, 30 percent oxygen, and 5 percent carbon dioxide. The reservoir of nutrient media was connected to the reactor jar so that it could be drawn freely into the reactor jar as the volume decreased. Incubation took place at 28 to 30C until the oxygen was consumed. A daily record of the gas level was kept, indicaing the rate at which oxygen was consumed by the microorganisms. These values could then be plotted on a graph. The equipment used by Straviniski is shown in Figure 28-6.

Blau (1943) used a fluorgraphic technique, not as a measure of the fluorescence of the oil itself, but as a measure of hydrocarbons of high molecular weight that have been formed by the action of certain organisms in the ground such as *Bacillus methanicus* or *Bacillus ethanicus.* These bacteria grow profusely in areas of leaking hydrocarbon gases and produce what appeared to Blau to be carboxyllic acids which fluoresce under ultraviolet light.

Among the variables that affect the bacteria population are, according to Soli (1954), (1) the moisture content of the soil; (2) temperature and pH; and (3) depth and surface-soil type. Beerstecher (1954) gives a more detailed account of the use of bacteria in prospecting for oil.

Conclusions

Successful geochemical prospecting for petroleum in this country must await the results of a vigorous integrated program of basic geochemical and geological research. The fruits of such a program would do much to re-establish this field of exploration on a new but much firmer base. The petroleum industry, continually faced with mounting exploration costs is reconsidering geochemical prospecting as an aid to oil and gas discovery. This is evident from a study of the programs of recent scientific society meetings wherein symposia entitled "Geochemistry in Petroleum Exploration" are being held with increasing frequency.

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Part Six

DRILLING, FORMATION TESTING AND WELL COMPLETION

Chapter 29 CONVENTIONAL ROCK BITS

L . L. Payne

This discussion outlines some of the problems confronting the operator in selecting proper bit types to accommodate various drilling conditions.

In proved fields, bit performance, together with geological data from adjacent completed wells, can and should be used in selecting bit types; however, quite often the operator has no definite information on wildcat drilling and even in some proved areas where faults and abnormal dips occur in the subsurface. In any event, if an operator is to drill a well economically, it is important that the general purpose of the bit design and the various types of bits be understood.

KINDS OF BITS

Figure 29-1 lists some of the more popular rock bits currently being used in drilling oil wells, together with the most common rocks for which they were designed. In addition, Figure 29-1 shows schematically a comparison of some of the important design features for the various bit types.

It will be noted from Figure 29-1 that 10 groups of bit types are shown; however, not all of these types should be used in drilling any one particular well. Generally, three or four types should be sufficient; in some areas only one or two types have been found adequate to drill economically a complete well.

Examination of the formation column shows that rock types fall into four general classifications given below.

General Classification	Bit Group No. (See fig. 29-1)
1. Soft formations	(1)
2. Medium-soft formations	(2) & (3)
3. Medium-hard formations	(4), (5), (6), (7)
4. Hard formations	(8), (9), (10)

Soft-Formation Bits (Group 1)

Bits in this classification are designed for drilling soft formations having low compressive strength and high drillability. Normally these bits are run with relatively light weights ranging from 1000 to 3000 pounds per inch of bit diameter. The rotary speeds range from 90 to 200 revolutions per minute.

The bearing capacity of any rock bit is a critical feature, and every effort is made to design the bearing to outlast the cutting structure; however, the bearings in this bit group do not require as great a capacity as for the other groups. This smaller bearing enables the designer to provide greater tooth depth. The teeth on these bits are widely spaced and relatively thin so as to permit deep penetration into the formation. The geometry is such that this bit subjects the formation to a maximum of gouging-scraping action with a minimum of chipping-crushing action.

Medium-Soft-Formation Bits (Groups 2 and 3)

The bit types shown in groups 2 and 3 are designed for those formations that are more compact than those just considered, but that still fall in the category of relatively soft formations. These formations may be interspersed with thin layers of medium-hard formations. The weights normally applied to these bits range from 2000 to 4000 pounds per inch of bit diameter with rotary speeds ranging from 80 to 125 revolutions per minute.

It will be noted from the design feature chart (fig. 29-1) that the bits in group 2 have a greater bearing capacity than those in group 1. Group 2 bits also utilize relatively slim teeth, but with slightly closer spacing and shallower depth. Additional gage hardfacing is also provided. In group 3, the tooth angles have been increased while the tooth spacing and depth have been further reduced. A larger amount of gage hardfacing has been provided than in group 2 bits. Groups 2 and 3 are also designed to provide a maximum gouging-scraping action and a minimum of chipping-crushing action.

Medium-Hard-Formation Bits (Groups 4, 5, 6, and 7)

The bit types shown in groups 4, 5, 6, and 7 are designed for both abrasive and non-abrasive medium-hard formations.

GROUP NO.	ROCK BIT MAKE AND TYPE									FORMATION	DESIGN FEATURES					CUTTING ACTION	
	HUGHES	CHICAGO PNEUM.	SECURITY	SMITH		REED		GLOBE		(CONSENSUS OF DATA CONTAINED IN EACH MANUFACTURERS CATALOGS)	BEARING CAPACITY	TOOTH INCLUDED ANGLE	TOOTH SPACING	TOOTH DEPTH	GAGE HARD FACING	CHIPPING CRUSHING	GOUGING SCRAPPING
	TRI-CONE	3 CONE	3 CONE	3 CONE	CROSS ROLLER	3 CONE	CROSS ROLLER	3 CONE	CROSS ROLLER								
1	OSC-3	ES-1C	S3	3C-DT	DDT	YT-3	2LT LT-3	SS3C	SS4C	SOFT FORMATIONS HAVING LOW COMPRESSIVE STRENGTH AND HIGH DRILLABILITY (SOFT SHALES, CLAYS, RED BEDS, SALT, SOFT LIMESTONE, UNCONSOLIDATED FORMATIONS, ETC.)							
2	OSC-1 OSC-1G	ES-1	S4	3C-DT2	K2	YT-1	2LM LT	S3C	S4C	SOFT TO MEDIUM FORMATIONS OR SOFT INTERSPERSED WITH HARDER STREAKS (FIRM, UNCONSOLIDATED, OR SANDY SHALES, RED BEDS, SALT, ANHYDRITE, SOFT LIMESTONE, ETC.)							
3	OSC	ES-2 ES-3	S6	3C-K2P	K2P	YT	T 2T	M3C	M4C	SOFT TO MEDIUM FORMATIONS INTERSPERSED WITH HARD STREAKS (MEDIUM HARD AND UNCONSOLIDATED SHALES, RED BEDS, SALT, ANHYDRITE, MEDIUM HARD LIMESTONES, UNCONSOLIDATED SANDS, ETC.)							
4	OWV	EM-1V	M4N	3C-SV2	K2P	YS-1				MEDIUM TO MEDIUM HARD FORMATIONS (HARDER SHALES, SANDY SHALES, SHALES ALTERNATING WITH STREAKS OF SAND AND LIMESTONE, ETC.)							
5	OW		M4	3C-2	C2K	YS	2HM	MH3C	MH4C	MEDIUM HARD FORMATIONS (HARD TOUGH SHALE, SANDY SHALE, HARD LIMESTONE, ANHYDRITE, DOLOMITE, HARD ROCK INTERBEDDED WITH TOUGH SHALE, ETC.)							
6	OWS	EM-3	M5	3C-2	C2K		2H	MH3C	MH4C	MEDIUM ABRASIVE TO HARD NONABRASIVE (HARD SHALE, HARD LIME, HARD ANHYDRITE, DOLOMITE, CHALK, SLATE, HARD ROCK INTERBEDDED WITH TOUGH SHALE, ETC.)							
7	OWC	EH-1	M4L	3C-T2	C2K	YM	2HS-1 2HS-1W	MHT3C		MEDIUM HARD ABRASIVE TO HARD FORMATION (HIGH COMPRESSIVE STRENGTH ROCK, DOLOMITE, HARD LIMESTONE, HARD SLATY SHALE, ETC.)							
8	W7	EH-1	H7	3C-4	4	YH	2C			HARD SEMI-ABRASIVE FORMATIONS (HARD SANDY OR CHERT BEARING LIMESTONE, DOLOMITE, GRANITE, CHERT, ETC.)							
9	W7R	EH-2 EH-3	H7W	3C-4W	4W	YH W	2C W 2C WW			HARD ABRASIVE FORMATIONS (CHERT, QUARZITE, PYRITE, GRANITE, HARD SAND ROCK, ETC.)							
10	R-1						COBRA			EXTREMELY HARD, ABRASIVE FORMATIONS (CHERT, QUARTZITE, GRANITE, FLINT, NOVACULITE, TACONITE, BASALT, QUARTZITIC SAND, ETC.)							

FIGURE 29-1. Grouping of rock bit types in relation to drillability of formations and basic design features. (This table does not include all makes and types of bits available. The charts on design features are general comparisons and are based on one size range of one manufacturer.)

It will be noted from Figure 29-2 that the principal design differences are in the progressive strengthening of the teeth and a change in the geometry to provide more chipping-crushing action with less gouging-scraping action. The

Figure 29-2. A bit principally designed for chipping-crushing of extremely hard and abrasive formations.

bit types shown in group 4 are for the softer end of the range of medium-hard formations. The teeth on group 4 bits are slightly slimmer and more widely spaced than those on bit types in groups 5, 6, and 7. The amount of gage hardfacing is comparable to those bits in group 3; however, the cutting action is essentially the same in all four groups.

Weights used on group 4 bits normally vary from 2000 to 4000 pounds per inch of bit diameter. Rotary speeds vary from 75 to 125 revolutions per minute and are generally decreased as the weight is increased.

The bits shown in groups 5, 6, and 7 are designed to permit the use of the heavier weights needed to penetrate harder formations effectively. The rotary speeds are in the range of 40 to 60 revolutions per minute when heavier weights are used.

Hard-Formation Bits (Groups 8, 9, and 10)

The bit types shown in groups 8, 9 and 10 are designed to drill hard formations that often have very abrasive properties.

The bearing size in these bits has been increased to provide maximum capacity. The tooth angles have been increased and teeth are more closely spaced. A sufficient increase in gage hardfacing has been provided to strengthen this part of the bit against abrasive wear. In addition, the geometry of these bits provides a maximum chipping-crushing action with a minimum gouging-scraping action.

The bits in groups 8 and 9 are designed for those formations generally requiring heavy weights, such as 4000 to 5000 pounds per inch of bit diameter and rotary speeds in the range of 40 to 60 revolutions per minute.

Bit types in group 10 are relatively new to the drilling industry. They have tungsten carbide compacts for the cutting elements instead of the more conventional chisel-shaped teeth. A three-cutter design of this type of bit is illustrated in Figure 29-2 and was designed primarily for the extremely hard and abrasive formations such as the chert sections in west Texas and New Mexico, and the hard quartzitic formations in Oklahoma and the Rocky Mountains. In these formations it is not unusual for one of these bits to drill 4 to 10 times the footage normally obtained with conventional hard-formation rock bits, and in some instances, 15 to 20 times the footage. The drilling rate of this bit will normally equal that of conventional hard-formation bits and has, in some instances, exceeded the penetration rate of regular bits by 50 to 100 percent or more. This type of bit usually drills at a constant rate of penetration throughout its life if the formation is uniform.

This bit may be considered a spot-bit inasmuch as it was designed primarily to drill those formations that not only are very abrasive but also have a high compressive strength. Although the cost of this bit is considerably more than the conventional rock bit, in areas where the depth and thickness of very hard and abrasive formations are fairly well known, it has proved very economical.

Experience indicates that the best operating practice in drilling chert or chert-bearing limestones is to carry a bit weight of approximately 4000 pounds per inch of bit diameter, using a rotary speed of approximately 35 revolutions per minute. Excess weight is not necessarily economical because it may result in breakage of the compacts and also reduce the life of the bearing.

Summary

From the foregoing discussion, it can be seen that bits are available for drilling any formation ranging from soft to hard. The big problem for the operator is when and where to use these various rock bits to the best advantage. Quite often the operator has no definite information as to the characteristics of the formations to be drilled. In these instances, examination of dull bits can be valuable in subsequent bit selection if the operator keeps in mind the fundamental differences in the various bit types. It should be remembered that each bit type incorporates certain design features and cutting actions that will enable it to drill a range of formations successfully. Bit selection by this method presupposes that the subsequent bit will encounter approximately the same formation. Unfortunately this is not always true, but it is a better approach to better bit selection than a blind guess.

The most economical rock bit performance can be obtained if optimum weights and rotary speeds are used. Sufficient weight must be applied to the bit to exceed the compressive strength of the formation, thus enabling the teeth to penetrate the rock; however, too much weight will cause the bit to ball up in soft formations or cause excessive tooth breakage and/or bearing wear in the more firm formations. Penetration rate tends to increase as rotary speed is increased, but excessive rotary speed can cause excessive tooth breakage and/or bearing wear, thus reducing the life of the bit. The operator must select his own operating conditions to suit the particular formations in which he is drilling; he must compromise between weights and rotary speeds in attempting to arrive at a combination that will most economically drill the formation. Under certain conditions, the operator may find it advisable to apply light weights; although by using such weights, it may make the formation appear much harder than it really is. In these cases it would be advisble to use a softer formation bit.

The type of drilling fluid used should be considered in bit selection. A change from water to mud will decrease bit performance without formation variation being involved. This change might give the impression that the formation is harder, and result in selecting the wrong bit type.

In most areas it is possible to use group 1 types for spudding in and drilling the upper portion of the hole. These types should be used as deep as possible,

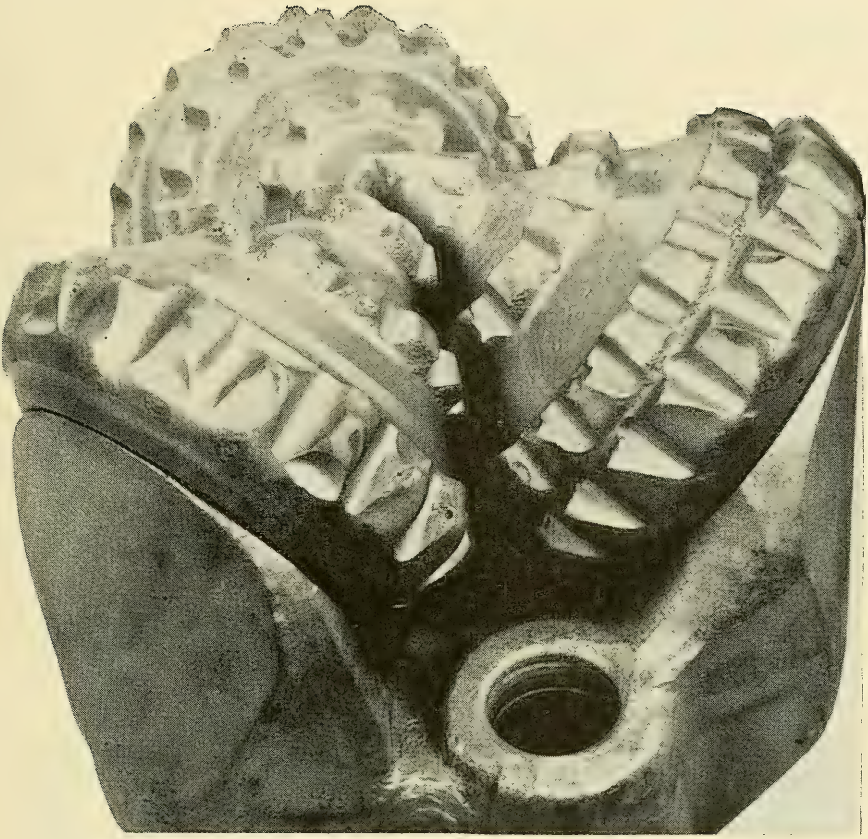

Figure 29-3. A bit showing excessive wearing and rounding of the gage surface.

because the softer the bit type, the faster the drilling rate provided the formation is not too hard. The depth to which any bit type can be used economically varies with the stratigraphy of the area and the drilling procedure.

In general, excessive bearing wear should not be used as a criterion for changing to a harder formation bit without first considering operating conditions and the condition of the dulled cutting structure. Heavy or light weights in combination with high rotary speeds can cause excessive bearing wear, particularly if abrasive muds are used. A change to a harder bit type with a larger bearing would reduce the bearing wear, but would probably result in a slower penetration rate. An adjustment in operating practice might enable the operator to continue to use the softer bit type more economically.

The examination of the worn cutting structure offers an excellent means of determining the proper bit for the formation being drilled. Excessive or unusual wear should provide clues as to what features need additional strength. Bit selection should be based on these observations.

EXAMPLES OF BIT WEAR The following illustrations are representative of a few typical worn bits. Figure 29-3 shows a bit that has undergone excessive wear and rounding of the gage surface. It is a medium-soft formation type having interruptions of the gage teeth. These interruptions reduce the amount of hardfacing available for resisting gage wear. This bit has a small amount of offset and consequently is more vulnerable to this type of wear because offset produces a wiping action at the gage. Such wear indicates that the formation was too abrasive for this particular bit, or that the

FIGURE 29-4. A bit showing extreme gage wear.

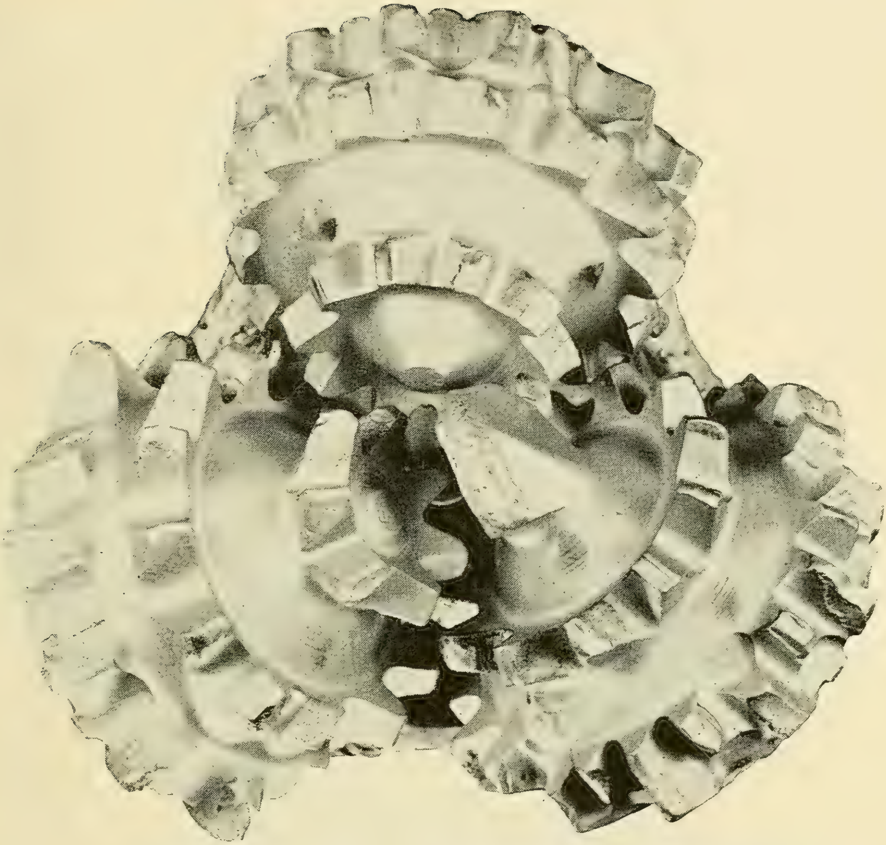

FIGURE 29-5. A dull bit showing excessive tooth breakage.

bit has been run too long. The solution to this problem is to reduce the rotating hours, or to change to a bit type having more hardfacing at the gage. When such wear occurs on a soft or medium-soft-formation bit, one should not immediately decide to use a hard-formation bit with maximum gage protection because such a decision may result in uneconomical drilling costs. The extent of the gage wear, condition of inner-row teeth, and length of rotating hours may indicate that only slightly more gage protection is needed, and it might be found advantageous to select a medium-hard-formation bit.

Figure 29-4 shows the results of extreme gage wear. Note that wear has progressed to a point where the roller bearings have been lost. This bit was run much too long in a hard, abrasive formation. A bit in this condition indicates that a portion of the hole drilled was not economical since some of the hole produced by this bit would be undergage and would require reaming by the following bit, thus reducing its life in terms of new penetration.

Figure 29-5 shows a dull bit with excessive tooth breakage, which can be caused by excessive weights and/or rotary speeds that produce high impact loads. Breakage may also occur if the formation is too hard for the bit. A moderate amount of tooth breakage or chippage is not uncommon and is not particularly detrimental. In fact, the complete absence of chipping and breakage sometimes indicates that a softer formation bit should be used, or that the operating conditions are not correct for best bit performance. If tooth breakage appears detrimental to bit performance, the selection of a harder type, or a change in operating conditions (lighter weights, slower rotary speeds, or both) is indicated. In general, the hardfacing that is applied to the teeth to resist

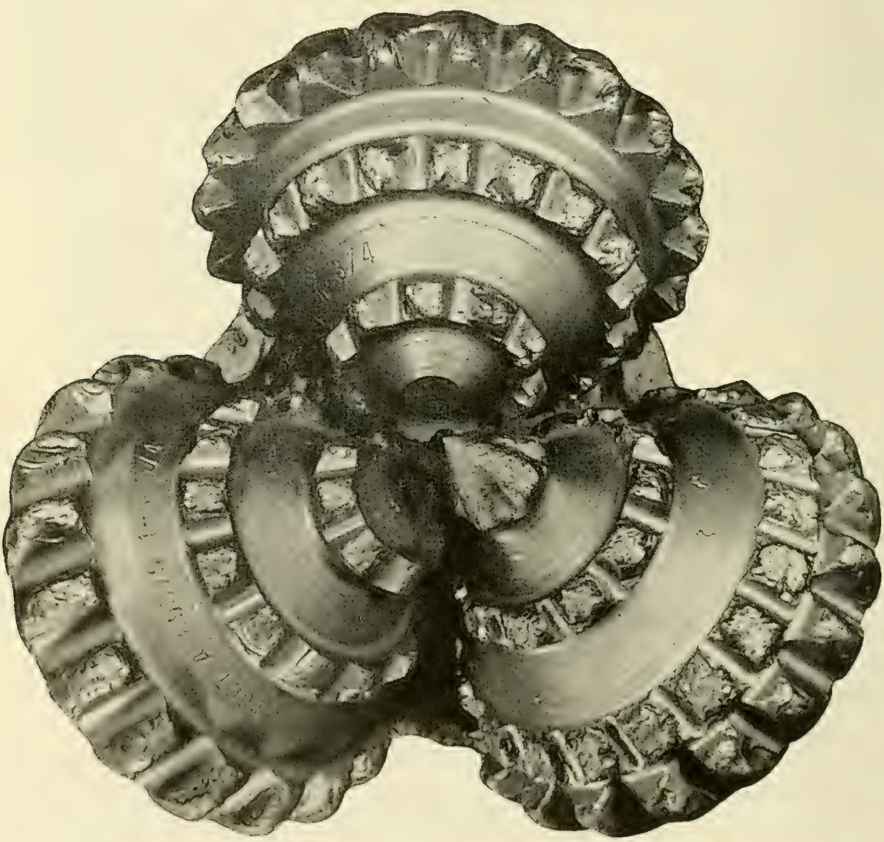

FIGURE 29-6. A bit showing severely chipped and upset teeth.

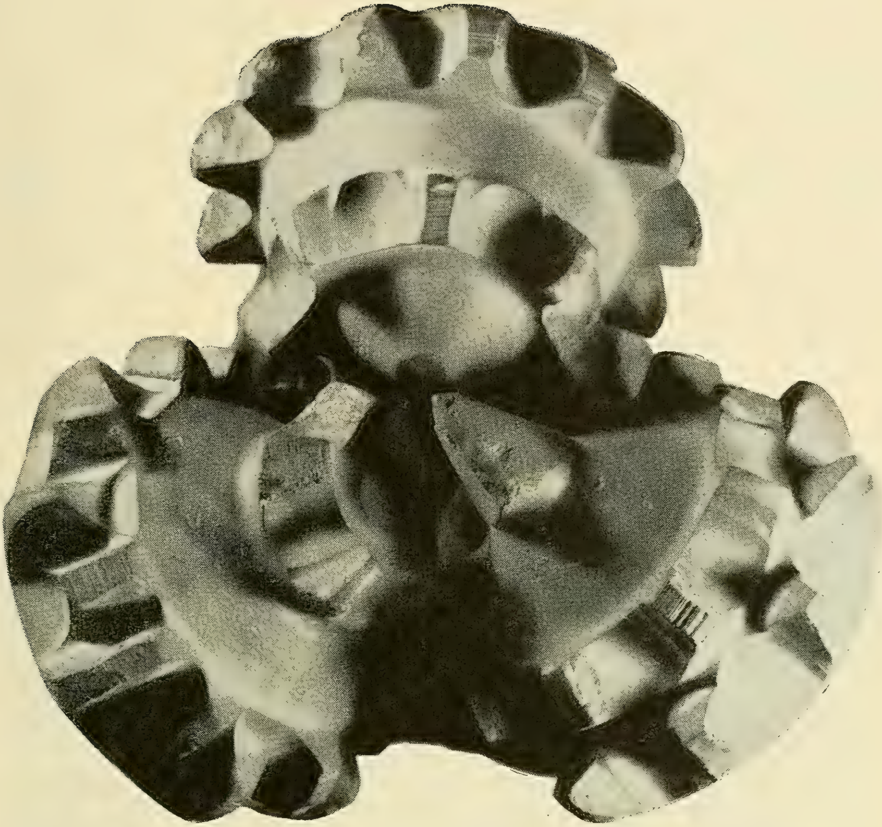

FIGURE 29-7. A bit which has been operated in a "balled up" condition.

abrasive wear causes reduced resistance of the teeth to chippage and breakage. The elimination of the hardfacing from the teeth, particularly in hard formations, will reduce chippage and breakage.

Figure 29-6 shows a bit with severely chipped and upset teeth. This type of wear is not unusual because it follows the pattern of the normal way that bits dull on hard formations (limestone or dolomite) under heavy weights. As the bit dulls, the case-hardened surface of the teeth wears and chips away and exposes the tough core to the formation. When teeth are dulled in this manner, the driller may apply more weight to maintain drilling rate and cause upsetting of teeth. This type of wear is quite often erroneously interpreted as being the result of improper heat treatment. Improved performance can be obtained by selecting a harder formation bit type. The harder types are usually available with non-hardfaced teeth.

Figure 29-7 shows a bit that has been operated in a balled-up condition. It will be noted that the cones have dragged even though the bearings are in good condition. This type of wear usually occurs in very soft, sticky formations. Balling-up can be the result of (1) the use of excessive weights which causes the teeth to penetrate too deeply into the formation, or (2) the use of insufficient circulating fluid to remove the cuttings. The formation then becomes packed around the cutters and causes them to drag or stick, thus wearing away the teeth exposed to the bottom and sides of the hole. This type of wear can be minimized by (1) decreasing the weight on the bit; (2) increasing the volume or velocity of the drilling fluid; or (3) some combination of these factors.

Figure 29-8 illustrates a condition, though not common, that can cause a reduction in bit performance in very soft, easily drilled formations. Note the

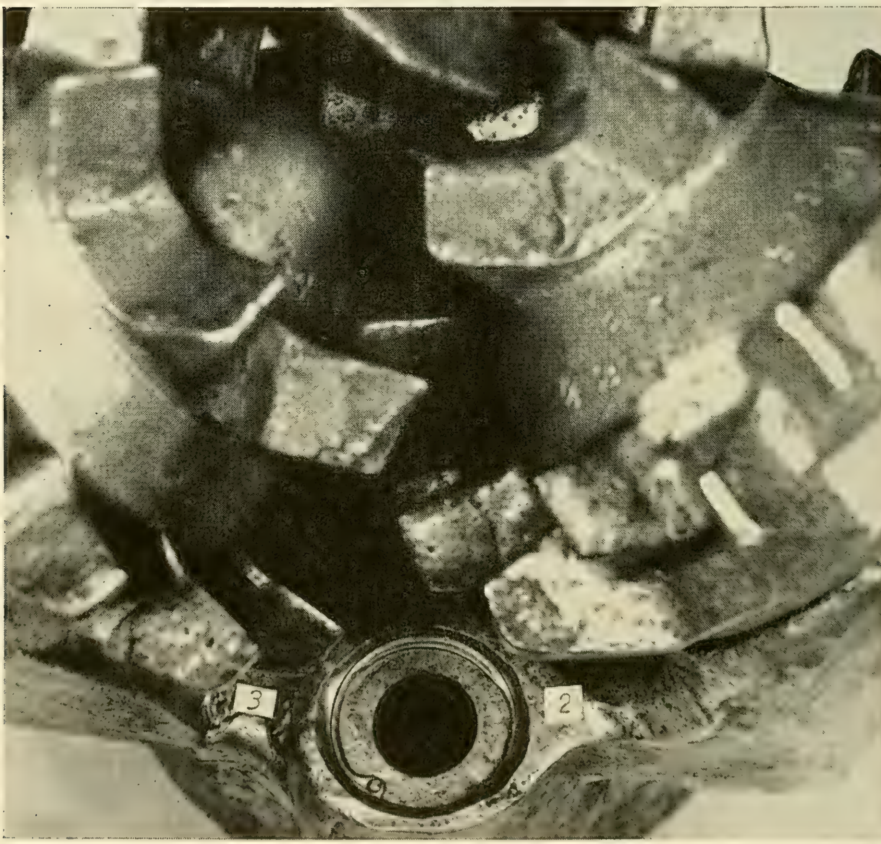

FIGURE 29-8. A bit affected by drilling in soft formations.

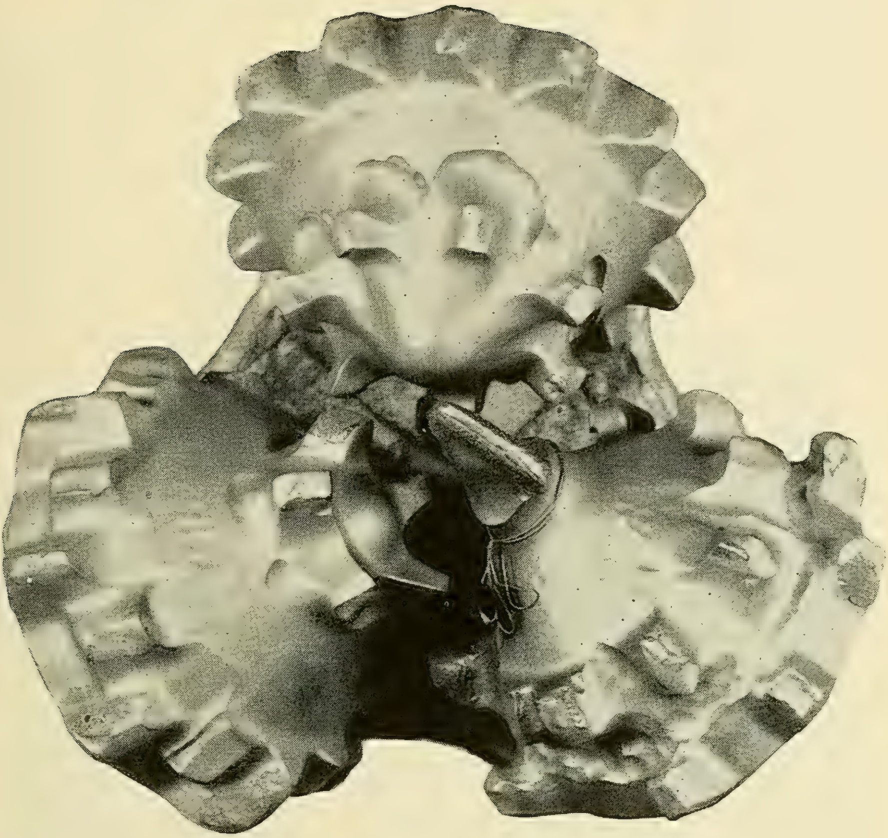

Figure 29-9. A bit severely eroded by the mudstream.

erosion of the nozzle-retaining ring and the head-section material adjacent to the exit end of the nozzle. If conditions that cause this erosion persist, the support for the ring will be eroded away, and the nozzle will be blown out of the bit. Failures of this kind are associated with high drilling rates and inadequate jet velocities that promote balling-up. The mud stream is deflected by the balled-up formation around the cutters so that it strikes the face of the nozzle and causes rapid erosion. Failures of this kind can be prevented by adjusting the operating conditions.

The cones on the bit in Figure 29-9 have been eroded severely by the mud stream from the conventional drilled water courses. In a bit having conventional drilled water courses, the nozzles are positioned so that the drilling fluid is directed onto the cones for cleaning purposes, usually at velocities of 100 feet

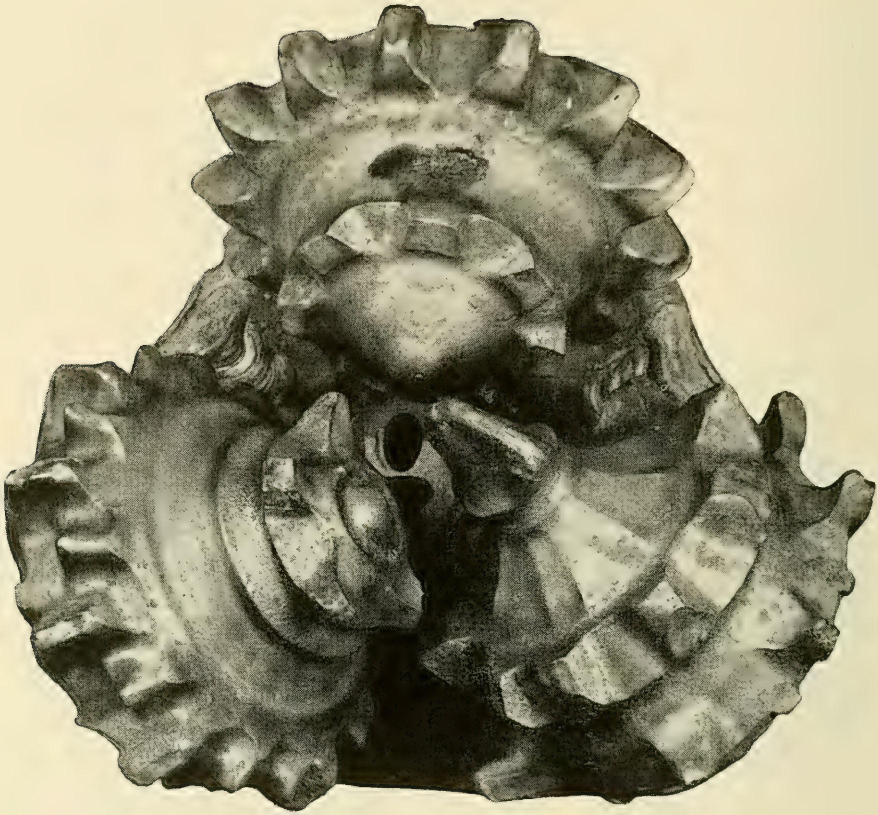

FIGURE 29-10. A bit showing off-center wear.

per second, or less. In bits having jet water courses, the nozzles are positioned so that the jet stream is directed onto the bottom of the hole; the resulting turbulence tends to keep the cones clean. The velocities used through jet bits are much higher, usually 200 feet per second or more. The type of wear shown in Figure 29-9 occurs only on those bits having conventional water courses and is caused by excessive velocity of the flushing fluid, particularly if abrasive muds are used. This condition can be alleviated by the use of jet bits where the fluid stream impinges on the bottom of the hole instead of on the cones. If the performance does not justify the small additional cost of jet bits, this trouble can be eliminated by reducing the velocity of the fluid streams either through the reduction of the circulated volume or by increasing the effective area of the water courses. Normally if the velocity of the flushing fluid is less than 100 feet per second through conventional water courses, erosion such as illustrated here does not occur.

Figure 29-10 shows a bit with off-center wear and has rotated about some center other than its own. Little is known of what actually causes a bit to run off-center, but such is introduced with drilling certain shales where crooked-hole problems necessitate the use of light weights on the bit. Apparently under these conditions, the wall of the hole is not strong enough to keep the bit from wandering. When this happens, the cutting structure no longer covers the entire bottom of the hole, and ridges of uncut bottom build up and rub against the cone shells. Once this condition starts, it progressively becomes worse because the ridges of formation rubbing on the cone shells further decrease the penetration rate and cause the bit to drill an even larger hole. This condition can best be prevented by increasing the weight on the bit.

Figure 29-11 illustrates an extremely dull bit that has been used long past its economical life. In addition, the severe gage wear shows that the considerable

FIGURE 29-11. A bit showing extreme wear.

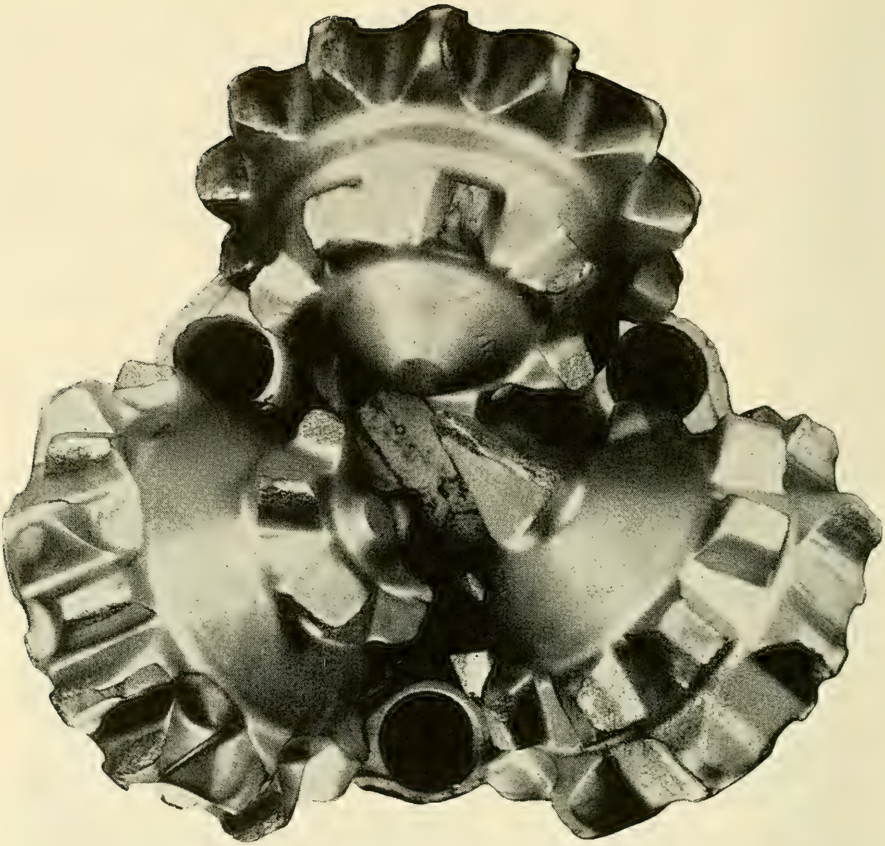

FIGURE 29-12. A bit showing normal wear from soft formation.

amount of undergage hole drilled will have to be reamed by the next bit. There is not enough of the cutting structure left on this bit to be of use in selecting of the next bit type.

The bit shown in Figure 29-12 is considered to be in a desirable dull condition for a soft-formation type, except that there appears to be considerable life still remaining in it. It will be noted that there is no tooth breakage and very little tooth chippage. The hardfacing has very effectively protected the tooth flanks from wear. Also, the pattern of hard facing has been effective in causing the teeth to wear so that they have remained relatively sharp, even though an appreciable amount of tooth height has been worn away. This condition represents a good selection of bit type and operating conditions for the formation being drilled.

Chapter 30

JET BITS

W. M. Booth
and
R. M. Borden

A jet bit is any drilling bit in which nozzles directed at the bottom of the hole utilize hydraulic power to assist in the drilling process. Certain basic differences between jet bits and conventional bits must be understood in discussing theory of drilling operation. In a conventional bit, the mud is discharged through relatively large orifices, usually one to three in number, so that the streams impinge on the cones or cutters. This discharge produces a cleaning action on the cones or cutters, and the mud deflects sideways toward the wall of the hole. In a jet bit, the mud is discharged through somewhat smaller orifices at a higher velocity and is directed so that it impinges on the bottom of the hole. The theory of operation of the jet bit, then, is that the mud-stream energy is used to remove loosened chips of formation from the bottom of the hole so that repeated cutting action by the bit teeth is not required to remove the chips. Conserving tooth structure in this manner extends bit life and improves penetration.

The cleaning of the cones or cutters of the jet bit is accomplished by the turbulence created by the high-velocity streams as they strike the bottom of the hole. It is believed that the amount of cleaning necessary is reduced with jet bits because sticky particles of the formation are removed before they have an opportunity to adhere to the cutting units. Thus, high volumes of mud can be used to advantage and are essential to efficient operation of the jet bit. With a conventional bit, high mud volumes may have an undesirable erosional effect on the cones or cutters.

The classification of jet bits is much the same as that for conventional bits. The three-cone, two-cone, cross-section, and drag types are most popular. The three-cone bit, the most widely used, is illustrated in Figure 30-1. It has three conical-toothed cutters, which rotate on bearings. This bit normally has three nozzles located around the outside of the bit and between the cones. The nozzles are placed within a few inches of the cutting plane of the bit so that a minimum of energy is dissipated before the mud stream impinges on the bottom of the hole. The two-cone bit, which is shown in Figure 30-2, is similar in most re-

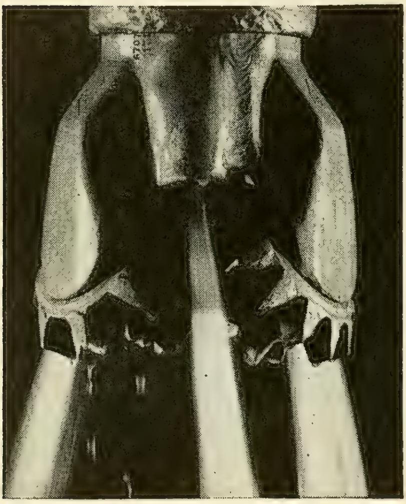

FIGURE 30-1. Three cone jet rock bit (courtesy Hughes Tool Company).

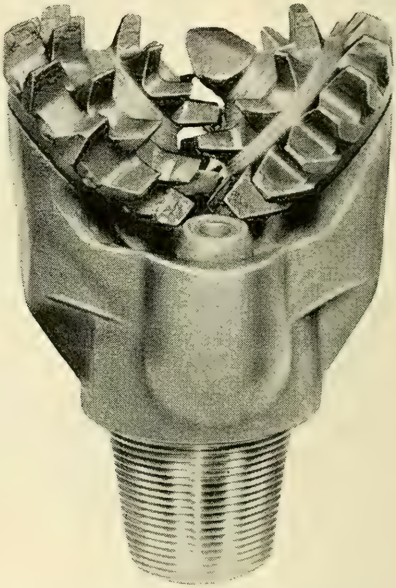

FIGURE 30-2. Two cone jet rock bit (courtesy Hughes Tool Company).

spects to the three-cone, except that it has only two cones and two nozzles. The cross-section-type jet bit is shown in Figure 30-3. It consists of two elongated roller-shaped cutters, and two narrow cutters at the circumference, all of which turn on bearings and carry cutting teeth. Normally, two nozzles are placed in this bit so that the mud stream is directed to the bottom of the hole.

The jet drag bit (fig. 30-4) is sometimes used for drilling in extremely soft formations. It is becoming less popular and will not be considered in the following discussion. It may have two, three, or four blades and a comparable number of nozzles. The cutting action of this bit is one of scraping and peeling the formation.

As early as 1921, attempts were made to utilize the jet rock-bit principle. Comparatively little success was attained until about 1947, when it became apparent that the failure to indicate improved performance was a result of inadequate jet-nozzle velocities. In 1948, the Humble Oil Company began an extensive experimental program in an effort to determine the hydraulic requirements of the jet bit. From these investigations it was concluded that jet velocities in the order of four times those of conventional bits were desirable. Other factors had to be considered, however, because the premium price of jet bits and increased operating and maintenance costs had to be offset by the increase of apparent that the failure to indicate improved performance was a result of inadequate jet-nozzle velocities. In 1948, the Humble Oil Company began an extensive experimental program in an effort to determine the hydraulic require-

FIGURE 30-3. Cross-section jet rock bit (courtesy Reed Roller Bit Company).

FIGURE 30-4. Jet drag bit (courtesy Reed Roller Bit Company).

penetration rates obtained with jet rock bits. The tests were difficult to evaluate because very few rigs then operating were equipped with sufficient power and pump capacity to meet the hydraulic requirements. Those rigs that were properly equipped were concentrated in the West Texas and Gulf Coast areas.

Gradually more emphasis was placed on drilling-rig requirements: rotary speed, drill collars, horsepower, and pump size. At the present stage of development, it is diffcult to determine how much improvement was gained from the use of jet bits and how much was gained by improved engineering application of the known principles. Penetration rates by conventional rock bits have improved considerably as a result of improved drilling engineering. One fact is certain: the development of the jet rock bit has brought about improved penetration as a result of concentration of effort on improved drilling principles.

FACTORS RELATED TO APPLICATION OF JET ROCK BITS The use of the jet rock bit has brought about a change in the emphasis placed on the controllable and established conditions of rotary oil-well drilling.

A definition and analysis of controllable and established conditions will help clarify the application of jet bits. The conditions discussed here are those that pertain directly to the power applied to the rock bit or that contribute to bit performance. Established conditions referred to are those factors that are a part of the oil-well drilling rig at the time the hole is drilled. They are as follows:

1. Rock-bit size (determined by casing program)
2. Drill-pipe size
3. Tool-joint size
4. Drill collar O. D. (outside diameter)
5. Drill collar I. D. (inside diameter)
6. Drill-collar length
7. Stand-pipe size I. D.
8. Stand-pipe length
9. Length of discharge lines
10. Size of discharge lines
11. Kelly-hose I. D.
12. Kelly-hose length
13. Swivel-washpipe and fluid-passage I. D. and length
14. Mud-pump characteristic - volume
15. Mud-pump characteristic - pressure
16. Hydraulic horsepower available
17. Formations encountered in drilling the well

Consideration must be given each of these factors in planning a jet-bit program.

The controllable conditions are those factors that may be varied or changed, after drilling is begun, to meet the changing demands of the formation being drilled and the increase in hole depth. These factors include:

1. Slush-pump liner size
2. Slush-pump strokes per minute
3. Bit-nozzle diameter
4. Number of bit nozzles
5. Rotary-table r.p.m.

6. Weight on bit
7. Mud velocity at bit nozzles
8. Mud-annular velocity (between drill pipe and wall of the hole)
9. Pressure losses in the circulating system
10. Pressure losses at the bit nozzles
11. Mud properties, i.e., viscosity, weight, solids content, etc.
12. Horsepower expended at the bit
13. Rock-bit type (jet or conventional)

It will be noted that these factors are related to one another; that is, a change in mud-pump liner size, or volume delivered, will result in a change in pressure losses, annular velocity, etc. It is important, therefore, to understand that, due to the number of variables involved in the basic requirement of drilling the hole with a jet rock bit, an economic balance can be obtained to give the maximum rock-bit performance. Of course, this balance is achieved more by experience than by engineering calculation because the wide variation of the heterogeneous formations respond differently to combinations of these variables. Many operators believe, however, that there is a definite relationship between the nozzle velocity, which is a function of horsepower, and the rate of penetration, regardless of type of strata encountered. But despite this relationship, the remainder of the controlled conditions so effect the net penetration rate that to minimize the importance of any one of these conditions may result in a reduction of any gains made by determining the proper jet velocity. It is necessary at this point to clarify the relationship between the conditions and to determine how they eventually affect horsepower at the jet bit. Because horsepower expended at the rock bit is a function of several factors and can be expressed in a simple formula, the study of this formula and related ones will help integrate all these factors.

(HHP) Bit-hydraulic horsepower - $\dfrac{G \times P}{1714}$

(V) Bit-nozzle velocity - $\dfrac{.32G}{A}$

(P) Pressure drop across bit nozzle - $\dfrac{G^2 \rho}{12031\ A^2\ C^2}$

WHERE:

HHP - Hydraulic horsepower expended at bit nozzle
V - Jet velocity (feet per second)
P - Pressure drop across bit nozzle (pounds per square inch)
A - Nozzle area in square inches
G - Rate of mud flow (gallons per minute)
ρ - Mud density (pounds per gallon)
C - Orifice coefficient

The primary purpose for giving these formulae is to show the effects of one variable on the others. An examination of the established conditions will show that variations of diameter and length through the hydraulic system, mud-pump size, horsepower in the mud system, etc., will result in losses or gains at the rock bit. A variation in the controllable conditions will similarly result in hydraulic losses or gains at the rock bit. Although the established conditions noted all pertain to jet-bit hydraulics, some of the controllable conditions do not. Specifically, reference is made to the revolutions per minute of the rotary table and the weight on the bit. Although these factors do not pertain to jet-rock-bit hydraulics, they do pertain directly to the over-all rate of penetration because they are factors affecting the life of the rock-bit bearings and cones as well as the ability of these bits to break up the formation physically. These two factors are of utmost importance because they determine the rate at which the chips are broken away from the formation; they are not related to the jet-rock-bit principle. They are as important in drilling with any rotary bit.

In summary, rotary drilling with rock bits may be divided into two parts: (1) the physical breaking up of the formation and, (2) the removal of the cuttings from the bit teeth. The former pertains in part to the action of the rotary speed and bit weight, whereas the latter pertains to the jet-rock-bit principle.

Earlier in this chapter mention was made of the fact that, although it is possible to calculate the losses involved in the hydraulic system, experience is the primary factor in determining the practicability of the jet bit in various formations. It is from experience, therefore, that many operators have established arbitrary figures on required mud volumes and velocities. It has been noted that 180 feet per minute is the minimum annular velocity required to carry the cuttings to the surface. It also has been established that the minimum effective jet-nozzle velocity satisfactory for the use of jet bits is 200 feet per second. It is these two figures that have created the jet-bit controversy now prevalent in the drilling industry. On numerous occasions, it has been demonstrated that annular velocities below the arbitrary minimum would be sufficient. The implications are that, with a lower annular velocity requirement in a given hole with a given drill-pipe size, lower circulating volumes may be used. The effect of the lower volume requirement results in the use of less horsepower, and all related losses are decreased. The opportunity then arises to reduce rock-bit-nozzle sizes and thereby to increase horsepower expended at the bit without overloading slush pumps and engines. This factor would enable some rigs, now equipped for conventional bit drilling, to utilize jet rock bits with existing facilities, provided that it would be possible to attain the established jet-nozzle velocity of 200 feet per second. On the other hand, some operators believe that a jet-nozzle velocity of 200 feet per second is not adequate and that the higher the jet-nozzle velocity, the higher the penetration rate. As has been stated already, some believe that there is a definite relationship between nozzle velocity and penetration rate, but this relationship has not been consistent in practice; hence, is not universally accepted. The result of the higher nozzle velocity through increased mud circulation, with the resultant higher annular velocity, appears to be gaining in popularity at this writing and has brought about a minor modification in the specifications of the drilling rig. Five-inch drill pipe has shown a very marked increase in popularity due to its improved hydraulic characteristics over the more common $4\frac{1}{2}$-inch pipe. Although engines for drilling rigs were formerly matched to the drawworks or hoist, they are now being matched to the slush pumps to provide adequate pumping horsepower, a setup that invariably results in an excess of power for the hoist.

The purpose of this chapter is not to discuss methods for determining when or when not to use a jet bit, but basically to review the jet bit as an existing oil-well drilling tool. However, at this point we must discuss how to determine whether a rig is capable of drilling a hole with jet bits. When it has been established that a given annular velocity is required, or that a given minimum jet-nozzle velocity is required, it must be determined whether the total losses in horsepower will exceed the available horsepower on the surface. If it is established that this horsepower requirement is in excess of the existing power, a compromise must be made and a revised approach to the problem worked out. To calculate horsepower losses, manufacturers provide charts, formulae, and curves. With this information, horsepower losses in the entire system can be established, and resultant annular velocities and jet velocities can be determined. From these figures the operator is able to set the maximum depth limit of the jet-bit operation.

Although industry is reasonably sure that the jet-rock-bit principle is sound and of considerable value if properly applied, the lack of sufficient empirical data to supplement the arbitrary established data sometimes results in failure to improve penetration rates sufficiently to make jet-bit drilling economically feasible. There can be no doubt that, when applied properly, the jet bit has indicated improved penetration rates.

JET-BIT ECONOMICS The justification for the use of jet bits lies in their ability to reduce drilling cost. The economic evaluation of jet bits is complex and involves use of estimates for some variable-cost items such as service life of mud pumps, prime-mover maintenance, and maintenance of mud lines. Because the use of jet bits requires higher mud-pump pressure and horsepower, it is apparent that operating costs of the pump and associated equipment will be higher. To arrive at exact costs would require exhaustive testing over the entire life span of the equipment, which may be from 8 to 10 years. This compilation has yet to be done; therefore estimates must be made at this stage of jet-bit development. The following discussion will review the various cost factors pertaining to jet-bit operation on a typical 5000-foot drilling rig that operates at a cost of $1000 per day, plus the cost of conventional bits.

Cost of the Bit

Compared to the conventional bit, the jet bit is premium-priced because of the additional manufacturing cost of tungsten-carbide nozzles.

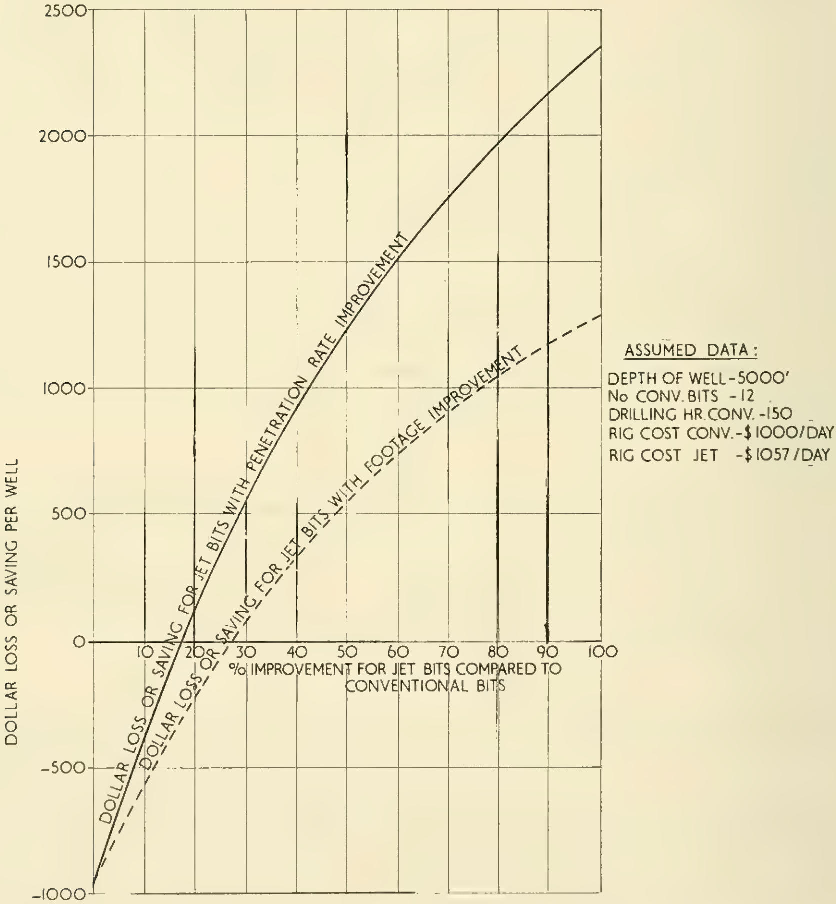

FIGURE 30-5. Chart showing dollars lost or saved by jet bits per 5000 feet well as a function of: (1) penetration rate improvement, when jet and conventional bit footage are identical, and (2) improvement in footage per bit when jet and conventional penetration rates are identical.

Pump Operating Cost

Little data are published relating pump-operating cost to horsepower output. In field tests, however, useful data have been compiled. For a pump in the 250-horsepower class, suitable for conventional drilling to 5000 feet, the daily maintenance cost for expendable parts was 21 dollars. A 400-horsepower pump used for jet-bit drilling to approximately the same depth operates for $30-per-day, representing an increase of $9-per-day for the jet-bit operation. Major overhaul costs are in addition to these daily maintenance costs; and since no exact figures are available, they must be estimated. It is reasonable to use a major overhaul cost of $5-per-operating-day for the 250-horsepower pump, whereas $8-per-day is estimated for the 400-horsepower pump. These costs are in the same ratio as the horsepower of the pumps, and they show an additional $3-per-day expense when jet bits are used. The sum of the expendable parts cost and the major overhaul cost indicates additional costs of $12 for jet-bit drilling.

Prime-Mover Operating Cost

The larger pumps required for jet-bit operation necessitate additional horsepower in the prime mover. For this example, it is assumed that power is supplied by a single diesel engine or group of diesel engines compounded. The additional operating costs resulting from the additional horsepower will be due to increased diesel-fuel and lubricating-oil consumption and to increased overhaul costs.

The present-day cost of diesel fuel is approximately one cent per brake horsepower hour. Normally, the pump will be in operation 18 hours in each 24-hour day, and the fuel cost would thus be $45-per-day for the 250-horsepower prime mover, and $72-per-day for the 400-horsepower engine, an additional $27-per-day cost for jet-bit operation. Additional lubricating-oil cost is estimated at $3-per-day and major overhaul cost will approximate an additional $3-per-day, making a total operating cost disadvantage of $33 for the jet bits.

Miscellaneous Costs

As a result of higher pumping pressure for jet bits, higher operating costs will be realized for the mud lines and valves, rotary hose, and swivel. In the absence of precise figures, $5-per-day additional cost is estimated.

Depreciation

The foregoing discussion has been concerned only with direct operating costs. In addition, there must be higher depreciation rates charged against a rig operating jet bits due to the increased capital investment in a larger pump and prime mover. This capital investment can be determined by using cost figures of $65 per installed horsepower for the pump, and $50 per installed horsepower for the prime mover, or a total of $115 per horsepower. The additional 150 horsepower required for jet bits would thus necessitate an additional capital investment of 150 × $150 or $17,250. Based on straight-line depreciation for 2000 operating days and 20-percent salvage value, the increase in depreciation is $7-per-day.

Summary of Costs

To recapitulate, the additional daily costs incurred in operating jet bits compared to conventional bits are as follows:

Item	*Additional Rig Costs Per Day For Jet Drilling*
Pump	$12.00
Prime Mover	33.00
Misc. Equipment	5.00
Depreciation	7.00
Total	$57.00

Thus, the five thousand foot drilling rig which would operate for $1000-per-day when using conventional bits, would be expected to operate for $1057-per-day when jet bit drilling. In addition, the jet bit itself would be priced at a premium of $32 each.

Profitability of Jet Bits

In order to appraise jet bits from a profitability standpoint in a given well, it is necessary to know the following information:

(a) Performance of jet bits compared to conventional bits in penetration rate.
(b) Performance of jet bits compared to conventional bits in total footage that can be drilled with each bit.
(c) Rig operating cost with jet bits compared to conventional bits.

PERSONNEL FACTORS

The successful use of jet bits depends not only on adequate equipment applied to favorable formations but also on proper training and attitude on the part of the drilling-rig crews. If the personnel involved are competent and are receptive to ideas that may improve the rig's performance, the chances of successful use of jet bits will be greatly increased. Further, if prior training of the rig crews and foreman can be conducted, better results will be realized. This training should include discussion of the theory of operation and instruction in how to determine proper jet-nozzle sizes, nozzle velocities, mud-rising velocities in the annulus, and mud-pressure losses throughout the hydraulic system. Much assistance in this training has been provided by data books and pamphlets developed by manufacturing companies and oil-industry associations.

Another important phase of training is safety. Because jet-bit operation will increase mud pressures, it is essential that rig crews are aware of the additional hazard. The equipment in the hydraulic system, such as pipe, valves, and fittings, must be checked more carefully and must be maintained in better condition to withstand the additional pressure.

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Chapter 31 TURBINE DRILLING

J. B. O'Connor

Turbine drilling is a basic extension of the rotary drilling method, with the motive power supplied directly to the bit. It uses a subterranean, fluid-actuated turbine instead of drill pipe to rotate the bit. This new method of drilling is destined to be an important adjunct to rotary, and in many instances to take the place of other methods of drilling.

The theory of drilling with the power source at the bit has held promise for many years as the ultimately logical method of drilling. The power loss inherent with conventional rotary drilling makes it an inefficient method, especially for deep drilling. Through its operating characteristics the turbodrill provides more power to the bit and eliminates many of the disadvantages of the rotary method.

DEVELOPMENT

The development of the modern turbodrill has required many years of research. In 1873, C. G. Cross obtained a patent entitled "Improvements in Drill for Boring Artesian Wells." This design involved a single-stage hydraulic turbine used for drilling with diamond-drill bits. In 1884, George Westinghouse, Jr., secured patents that proposed a similar unit, but one that used a positive-displacement motor instead of a turbine. These two designs were the first attempts toward the basic concept of the turbodrill.

It was not until 1924, however, that any real progress was made toward creation of our modern-day drilling turbine. In that year, C. C. Scharpenberg, of the Standard Oil Company of California, secured patents for a multiple-stage turbine remarkably similar in design to those used today. In 1926, the protoype of the Scharpenberg drill was used for experimental work in California. The

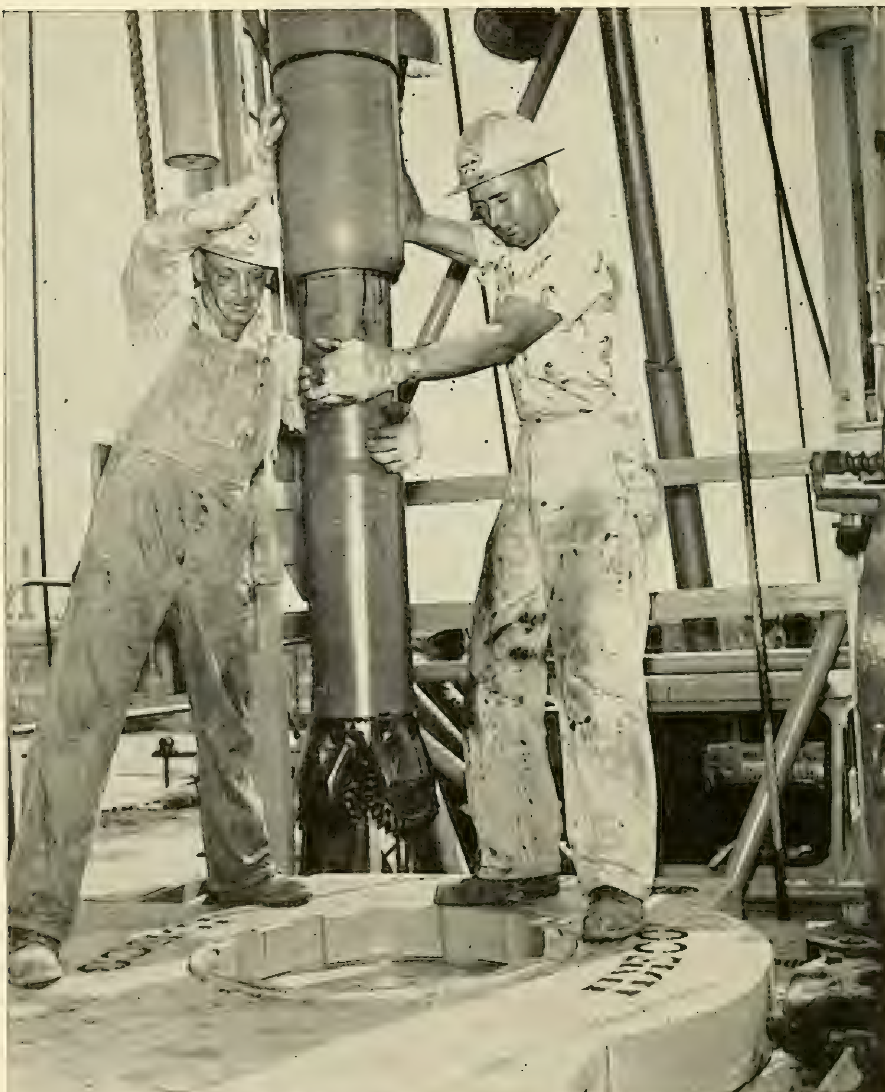

FIGURE 31-1. Turbodrill being tested at Dallas, Texas.

mechanical possibilities of this new tool were quickly demonstrated, but the unit failed to meet commercial expectations. In this early construction, metallic bearings were used to carry both the radial and thrust loads of the turbine. As a result of the abrasive action of the drilling fluid, seals that were designed to exclude fluid from the bearings always leaked.

Because of this failure, a joint development program with the A. O. Smith Corporation was undertaken on the Scharpenberg drilling turbine from 1935 to 1941 and again from 1949 to 1950. Progress was realized in the early phase of this development stage when rubber journal bearings were developed to replace the metallic radial bearings. Some progress was also made toward the development of adequate thrust bearings. However, bearing difficulties still occurred, and further development of the Scharpenberg drill was abandoned in 1950 after units failed to show sufficient improvement over rotary methods.

From about 1925 to the present, the Russians have spent considerable effort to develop an efficient, workable turbodrill. In 1948 they substituted mud-lubricated, multi-disk rubber thrust bearings for the steel ball bearings that had been used up to that time. This innovation contributed greatly to the successful development of a practical turbodrill. At present, Russia is reported to be drilling more than 80 percent of its wells with the turbodrill. Considerable development has also been made in France on the turbrodrill. The French turbine is essentially an adaptation of the Russian design.

In 1956 Dresser Industries, Inc., acquired 40 of the Russian turbodrills (fig. 31-1) for field testing and entered into an agreement with the French to work closely on future developments in turbine drilling. These turbodrills are being tested in several oil areas in the United States.

COMPARISON OF TURBODRILLING WITH ROTARY

In many instances, the turbodrill appears to be an extremely promising substitute for the conventional rotary, especially when drilling below 6000 or 7000 feet. The turbine method may permit drillers to penetrate deeper than is possible with the rotary system because the turbodrill is not limited by the mechanical characteristics of the drill string.

With the present rotary, the drill stem is a long, limber power shaft that is influenced by vibrations, wear, and both dynamic and static torque. The great losses in transmitting power characteristic of this system result mainly from the friction between the pipe and hole and the viscosity of the drilling fluid. Rotating speed is limited due to whipping of the drill string; torque is limited to the dynamic torsional strength of the drill pipe.

It is estimated that less than 10 percent of the power delivered to the rotary table reaches the bit because of the power losses incurred in rotating the drill string. This estimate is probably low in wells less than 8000 feet deep, but may be quite high for wells more than 10,000 feet deep. A number of experiments indicate that under present rotary methods only 10 to 25 horsepower is actually utilized in drilling deep wells. The remaining power is consumed in transmission.

In turbine drilling, rotating power is generated just above the bit, with the result that the bit is rotated with greater efficiency. Since it is not necessary for the drill string to rotate, fatigue failure of the pipe is greatly reduced, and wear is almost eliminated. The loss that occurs in transmitting the hydraulic power to the turbine is caused by drill-pipe pressure drop, which can be adequately controlled through selection of the proper size of drill pipe. It can be easily recognized that turbine drilling permits more power to be applied to the bit with greater efficiency.

For example, a turbine and hydraulic system may have an efficiency of 60 percent, and this system is powered by a mud pump having an efficiency of 70 percent. If 300 horsepower is applied to the mud pump, the power available at the bit is 126 horsepower in turbine drilling. Since approximately only 10 percent of the power reaches the bit in a conventional rotary system, 300 horsepower applied by the rotary table will provide only 30 horsepower to the bit. If the bit can use the power efficiently, the turbodrill would penetrate the formation at least 4.2 times faster than the conventional rotary. Power output applied to the bit by the turbodrill is reported to be 3 to 5 times the power applied by rotary.

In drilling with the turbodrill, the Russians usually drill a larger-diameter hole (12¼″±) than is customary with rotary (8¾″±) in the U. S. Thus the power per square inch of hole is not a direct ratio of the power applied to the bit, and a comparison of probable penetration rates based on power available at the bit may be misleading. For example, using rotary at a 10,000-foot depth with 4½-inch drill pipe, and a 7½-inch bit turning at 125 revolutions per minute, the Russians reported that the power transmitted to the bit was 40 horsepower or about 1.1 horsepower per square inch of hole. A turbodrill, using a 6⅝-inch drill pipe, a 12½-inch bit and a pump capacity of 800 gallons per minute, transmitted to the bit 200 horsepower or about 1.7 horsepower per square inch of hole bottom. One report comparing the drilling rates of turbodrill and rotary showed an average increase of 1½ to 2 times the penetration capacity with turbine drilling under similar conditions.

TURBODRILL CONSTRUCTION

The design of the turbodrill is relatively simple. Only five basic components make up the unit (fig. 31-2): (1) the body or housing, (2) the thrust bearing, (3) the turbine, (4) the lower bearing, and (5) the bit.

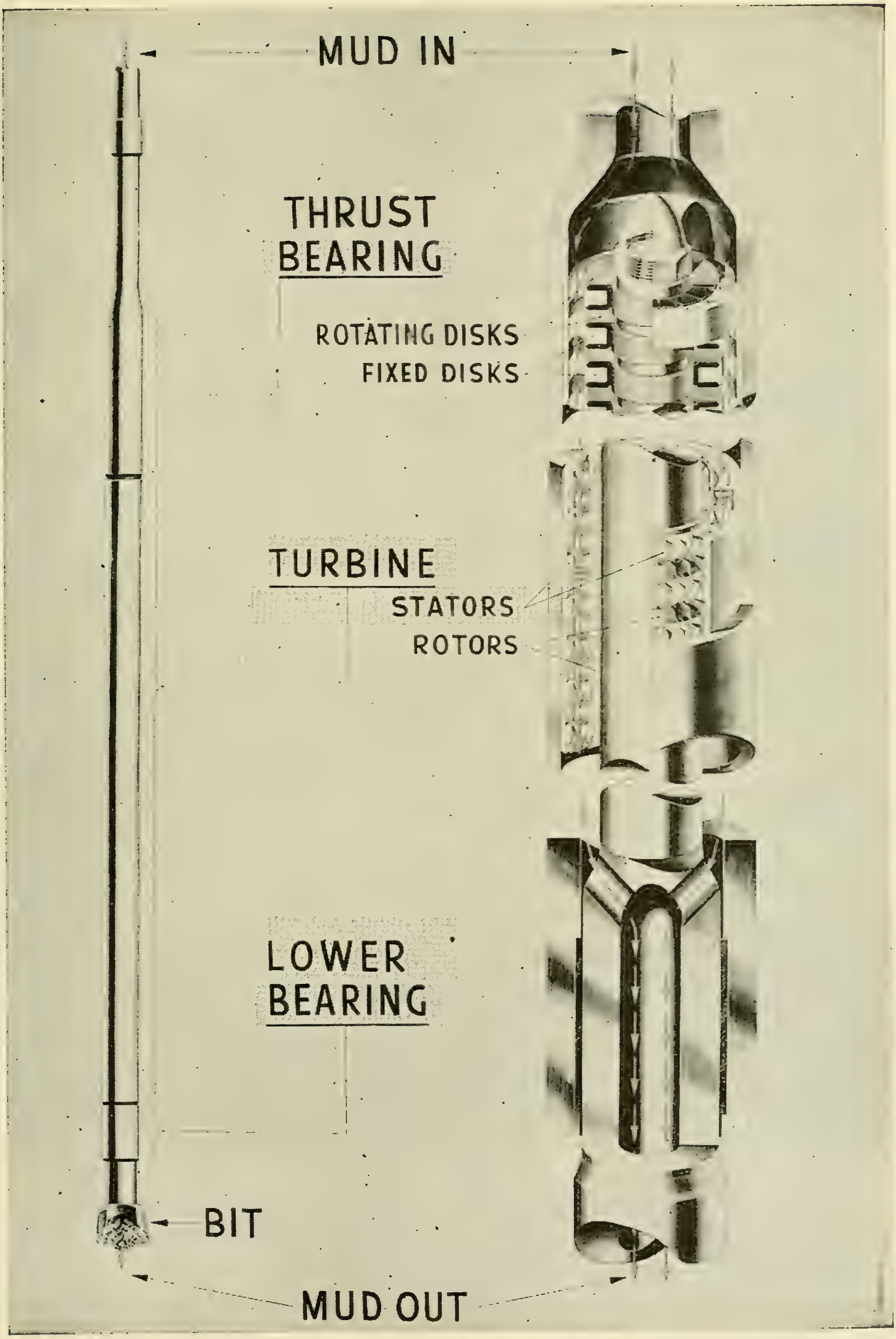

FIGURE 31-2. Complete turbodrill (left) and cutaway view (right) showing major components.

In the turbine body are 80 to 100 turbine stages, each composed of a fixed stator mounted in the main body. Each stator has blades to direct the fluid toward similar curved blades of the rotors on the rotating shaft. The fluid is forced through the turbine blading and imparts reaction torques on the blade of each stator and rotor. The fluid also lubricates and cools the bearings. The cumulative effect of the torque reaction created by all the stator-rotor stages in the turbine drives the bit.

The pressure drop of the liquid as it passes through the turbine generates two useful forces: the driving torque and the axial thrust toward the bit. Because all stator-rotor stages in the turbine are identical, the pressure drop across each stage is always the same. For instance, a turbine with a pressure drop of 6 pounds per square inch per stage would have a total pressure drop of 600 pounds per square inch in a 100-stage unit.

Unlike previous experimental models, the modern turbodrill has sufficient power and torque to drive the bit. Power of the turbodrill now ranges up to 300 horsepower; bit speeds are from 500 to 900 revolutions per minute with bit loads of 20 to 35 tons. The running torques which are on the order of 2000 to 3000 pound feet, are sufficient to rotate the bit under all normal drilling conditions.

TURBODRILL OPERATION

The operation of the turbodrill differs from the turbine in a hydroelectric plant in one way: the turbodrill operates at a constant flow and variable speed, whereas the turbines in hydroelectric plants work at variable flow and constant speed.

Usually the turbodrill requires no more pressure for its mud circulation than can be supplied by a rotary type rig equipped for jet drilling. Since the fluid pressure supplies the power in turbodrilling, all details of the mud lines must be studied with extreme care.

Where the formation permits, the specific gravity of circulating fluid used to operate the turbine should be nearly that of water in order to enable the pumps to supply high pressures and flows and to reduce both turbine and pump maintenance. Although turbines have been used successfully with mud having a density of 1.6 to 1.8, fluid with a density and viscosity nearly that of water—helps reduce bearing friction—often as much as 50 percent—and thereby releases considerable additional turbine power to the bit.

A method of obtaining even greater torques than are possible with one turbodrill is to use several turbodrills coupled together. They then cumulate torque and increase the axial thrust due to high pressure drop. Where a single 10-inch turbine gives an 18-ton axial thrust, the double turbine gives up to 25 tons for an equal flow of fluid.

Performance characteristics of a 10-inch turbodrill show that maximum power and maximum turbine efficiency are reached at a shaft speed of about 600 revolutions per minute, which is half the idling speed of 1200 revolutions per minute. The torque drops to zero at the idling speed. At the other extreme, if the turbine becomes stalled, the torque is twice that developed at 600 revolutions per minute. This fixed maximum torque at stall is automatic protection against overloading of the pipe in deep holes.

TURBINE DRILLING PROCEDURES

The technique of turbine drilling is relatively new to the American petroleum industry. When more experience is gained, new methods and new techniques will be developed. As a greater number of drilling crews become familiar with the operation of this tool, more precise methods of operation will be established. In general, it has been found that good rotary drilling practice is also good turbodrilling practice.

The first step in running a turbodrill, before running it in the hole, is to verify that it will start easily with low pump pressure. Then, with the pumps still operating at low pressure, the drill is lowered until it is a few feet off bottom. Full pressure is then applied to the turbodrill to redrill the last few feet of hole in order to avoid damaging the turbine by a return of cuttings inside the unit while it is still being lowered to bottom. When it is on bottom, the weight on the bit is gradually increased until the maximum power of the turbine is developed and the maximum rate of penetration of the formation is obtained. Before coming out of the hole, the turbodrill should be operated off bottom for a few moments to make sure that the hole has been thoroughly cleaned.

The following basic requirements may eventually be standard practice in outfitting a rig to an 8-inch- or 10-inch-diameter turbodrill:

1. A spare turbodrill should be provided for each rig to permit maintenance and continuity of drilling.

2. Pumping facilities are required to deliver approximately 800 to 1000 gallons per minute at sufficient pressure to satisfy the 600 to 1000 pounds per square inch additional pressure drop across the turbine. Rigs with pumps for jet bits may already have sufficiently high pumping capacity.

3. Effective pulsation dampeners should probably be used, particularly with mud pumps operating in parallel. Dampeners help to smooth the hydraulic loading on the turbine's thrust bearing, as well as the operation of the bit.

4. The drill pipe should be of a slightly larger diameter than is normally used with rotary. The larger pipe will help to reduce the pumping pressure and the power lost in friction. Tool joints should also be designed with a larger bore to cut down flow resistance. Dual or larger diameter stand pipe, and perhaps dual mud hoses may be recommended to provide a double connection into

the swivel. The kelly should be at least 6-inch, with a larger bore; and the circulation holes through the bit should be made large to accommodate the increased mud flow.

5. Drilling fluid should be desanded to minimize wear on both the turbine and mud pumps. The sand content should be kept to 1 or 2 percent if possible; it should never exceed 5 percent.

ADVANTAGES OF TURBODRILLING

The following advantages of turbodrilling tend to make it an important adjunct to the rotary system. In many instances, turbodrilling may make obsolete other presently known drilling methods.

1. Faster penetration rate: The availability of more power at the bottom of the hole produces drilling rates that are not possible with the conventional rotary. Then, too, as the hole deepens, the penetration rate of the turbodrill can be maintained more uniformly than that of the conventional rotary.

2. Straighter drilling: Because the bit speed in turbine drilling is higher and the bit weight generally lower than with rotary drilling, less deviation of the hole may be expected.

3. Full-gage drilling: Since in turbine drilling the drill stem does not whip, the hole has a more uniform caliper. This is an important advantage in running or cementing casing.

4. Better utilization of crew: Because of the potentially greater penetration rate with less down-time for equipment repairs, use of the turbodrill will permit a more efficient use of the drilling crew.

5. Little wear on drill pipe: The hard wear on the drill pipe, which is incident to rotary, is not a liability in turbodrilling. Because in turbodrilling drill pipe is not used to transmit power to the bit, and rotates at most only 1 to 15 revolutions per minute—usually not at all—drill pipe is not subject to hard wear. For this reason, drill pipe used in turbodrilling can be lighter and cheaper. The lighter duty on the non-rotating drill pipe is said to cause 2 to 3 times longer pipe life. Torque is less than with rotary, and it never approaches the peak torque values created by the sudden reactions of the bit in rotary drilling.

6. Fewer fishing jobs: Most of the causes of parted drill pipe are eliminated by turbine drilling. The pipe is never subjected to excessive torque because of the design characteristics of the turbine. Also, the pipe does not drag on the wall of the hole except at extremely low speeds. Twisting off of drill pipe does not occur. Turbine drilling does not create any new difficulties of this nature, but instead eliminates or reduces most of the existing dangers and difficulties encountered with rotary.

7. Less wear on rig: The wear on the swivel and the rotary table is considerably reduced in turbine drilling.

8. Clean hole: Lifting capacity of the drilling fluid is improved by the higher annular-velocity characteristics of turbodrilling. The cuttings are smaller because of the higher bit speed and can be carried out more efficiently.

9. Multiple operation: Several turbodrills can be coupled together in series to afford a reduction in flow rate and bit speed as the hole deepens, without sacrificing turbine-power output. Often the power may be increased. This flexibility in turbodrill operation provides a more effective relationship between torque, bit speed, and drilling weight to satisfy most drilling conditions that may occur, except perhaps in some soft formations.

10. Better directional drilling: Accurately controlled directional drilling is possible by the use of new turbodrill techniques, that do not require whipstocks.

11. Less maintenance: Swivel and rotary-table maintenance can be minimized because the pipe is turned only occasionally to free cuttings around the drill string, and to obtain accurate weight indications.

DISADVANTAGES OF TURBODRILLING

As with any drilling system, turbodrilling has its disadvantages.

1. Viscous-mud problem: If drilling conditions require an extremely viscous mud, the turbodrill should not be used because of the excessive pump pressures required.

2. Bit performance: Although the turbodrill increases the penetration rate of our present-day drilling bits to a remarkable extent, it should be possible with better bit design to extend the bit life considerably. The development of bits especially designed for turbodrilling is now being undertaken by Security Engineering Division in the United States, Security Rock Bits, Ltd., in England, and by other companies.

3. Soft-formation drilling: Because the turbodrill rotates between 600 and 800 revolutions per minute, some formations now drilled by rotary at bit speeds of 50 to 70 revolutions per minute may not respond as well to the turbodrill. Turbodrilling in soft, sticky formations in the Gulf Coast area, for example, may not equal or keep pace with certain rotary techniques now used with jet bits. However, the final answer cannot be obtained until there is more turbodrilling experience in America.

ECONOMIES OF TURBINE DRILLING

Although actual experience with the turbodrill in America is limited, authenticated reports from Russia indicate some evaluation of the turbodrill. In the Bashkir oil field between Bugulma and Tuymazy in the Tartar Republic, 170 drilling rigs were running in late 1956, all using the turbodrill.

The rapid development of this field is credited entirely to the use of the turbodrill. The Russians drilled wells in 8 days that would require 36 days by rotary; wells in this field are from 5400 to 5600 feet deep, and it is hard drilling practically all the way. An average of 61 bits per well and 100 feet per hour penetration rate is reported. A breakdown of the time spent on the average well is as follows:

Actual drilling time	54 hours
Adding Pipe	22 hours
Pulling pipe	126 hours
Total	202 hours

On some wells the Russians use from 20 to 27 tons of weight on a bit that runs at 400 to 900 revolutions per minute. Two 400-horsepower mud pumps operate at 1470 to 1760 pounds per square inch. With this rig and a 6⅝-inch turbine, they have drilled to depths of 15,000 feet.

Another operation witnessed in Russia was at a well drilling in dolomite at 1200 feet. A rotary system was run at 250 revolutions per minute, which is high for this formation. The weight on the bit was 20 tons, and the maximum rate of penetration was 4½ feet per hour. In the same formation a turbodrill with 20 to 24 tons on the bit drilled at the rate of 57 to 75 feet per hour. In both tests the mud pressure was 1470 to 1760 pounds per square inch, and the circulation rate was 950 gallons per minute.

In a Siberian well, the following comparison of turbodrilling performance with that of rotary was made:

	Rotary	Turbodrill
Penetration rate	15 ft per hr	48 ft per hr at 8 tons
		57 ft per hr at 10 tons
		75 ft per hr at 24 tons
Weight on bit	22-24 tons	8-24 tons
Bit speed	225 rpm.	900 rpm

Turbodrilling economies are obtained primarily because of an ability to afford faster penetration rates and lower drill-pipe costs. The lighter service imposed on drill pipe permits the use of lighter drilling strings, which reduces replacement costs. Although increased pump capacity is sometime required by the turbodrill, savings on overall drilling costs can be made through lower costs for drill pipe and other rig components.

The turbodrill promises to offer the oil industry a remarkably efficient drilling method. To what extent it will actually replace rotary drilling in America will be determined only after it has been used for considerable time in various domestic oil fields. The future for the turbodrill does, however, appear tremendous. With the development of this new drilling method, the geologist will have a more efficient drilling system for exploration. It is not unlikely that the present-day concept of wildcatting will be simplified. Equipment and time costs will be substantially reduced; penetration rates will be increased; and in most respects the work will be easier for the drilling crew.

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Chapter 32

DIRECTIONAL DRILLING

Harry C. Kent

Since the time of Titusville, crooked holes have been drilled in the search for petroleum. The early holes which deviated from the vertical were not intentionally drilled so, for we know today that many factors over which the early driller had no control contribute to the crookedness of wells. Such conditions as the pressure placed on the rotary bit, the dip of the formations, and the flexibility of the drill string must be considered by the well driller in order to make sure that the well is drilled as planned.

The older oil fields of the United States have many holes which trend far from the course intended. In fact, a number of early wells have later been found to have crossed lease boundaries in the subsurface and to have bottomed and produced under property not leased or owned by the well owners. With the advent of more modern well-drilling and surveying methods, it is now easy to see why earlier oil exploration was a hit or miss affair, and why so many wells apparently drilled to tap the most favorable part of the reservoir were poor producers or completely dry.

For a number of geological and engineering reasons, many exploratory and development oil wells are drilled at present with some deviation from the vertical. The application of techniques to control the deviation and direction of a well is known as controlled directional drilling. An understanding of this procedure has become of prime importance to both the petroleum geologist and the petroleum engineer.

Very probably the first intentional use of directional drilling was to by-pass lost tools or other junk in a well. After failing to retrieve the lost material by fishing, the driller would by-pass the obstacle by deflecting the bit with a crude whipstock. By this method the driller was able to salvage the portion of the well above the obstacle and minimize redrilling costs. This early whipstock was generally a tapered piece of timber which could be left in the hole after it had served its purpose. The setting of a more modern whipstock to by-pass lost tools in a well is still one of the commoner applications of directional drilling.

The Huntington Beach Oil Field in California was the site of the first extensive application of controlled directional drilling. This field, which extends from the shore oceanward about two miles, presented a problem in development which was solved by drilling directional wells from on-shore locations to subsurface bottom locations under the ocean. The many technical problems involved in the successful drilling of these wells (i.e., prevention of abrupt changes in drift and direction, avoidance of collision of drilling wells with older producing wells, etc.) accelerated the development of better techniques and instruments for well control and surveying.

WELL SURVEYS The techniques of directional drilling did not begin to assume their present importance in the oil industry until satisfactory tools for surveying the course of a well were developed. Early attempts at well surveying were crude, but they did give an indication of the inclination and direction of the hole. One early type of deviation survey was made with a weak solution of hydrofluoric acid in a glass bottle. The bottle containing the acid was lowered to the bottom of the hole and allowed to sit for 10 or 15 minutes, long enough for the acid to etch the glass. When removed from the well, the etched bottle gave an indication of the *angle* of inclination of the hole from the vertical, but not the *direction* of the inclination.

A modification of the hydrofluoric acid technique involved the use of a magnetic needle floating in gelatin. This arrangement was lowered into the hole and allowed to sit until the gelatin hardened. The inclination of the surface of the gelatin in the container thus gave an indication of the angle of the hole, and the orientation of the magnetic needle gave an indication of the direction of the hole.

Neither of the above early methods gave any assurance to the operators that they were measuring the *true* inclination of the hole. Erroneous readings were often caused by the jamming of the devices against the side of the hole or against an obstacle.

Three basic types of well surveying instruments are now in common use: (1) drift indicators, (2) single-shot instruments, and (3) multiple-shot instruments. Single-shot and multiple-shot instruments record both the *amount* and *direction* of inclination, whereas drift indicators record only the *deviation* from the vertical.

Well proposals and drilling instructions for most of the straight holes drilled at the present time require that the holes be drilled within a very few degrees (generally 3 to 5) deviation from the vertical throughout the course of the well. This requirement is necessary if the well is to reach the reservoir at the desired location and if there are to be no dog-legs which would give trouble when pumping equipment is installed. For this type of situation, the use of the drift indicator gives all the information necessary during the drilling of the well to satisfy the deviation requirements.

The simplest type of modern drift indicator, which utilizes a sharp-pointed plumb bob, is entirely mechanical in operation. As with most drift indicators and single-shot instruments, this indicator is operated usually by the drilling crew and does not require that a service company representative be present on each run. When a reading is to be taken, a timing device on the instrument is set for an interval long enough for the indicator to be run into the hole and to become stationary before the actual reading is taken. The reading is taken by means of a spring mechanism that forces a paper disc against the sharp point of the plumb bob. This disc is marked with a number of concentric rings that are calibrated to give the deviation in degrees from the vertical. Some models of this type of instrument are arranged so that after the first reading is taken, the disc is automatically rotated 180 degrees and a second reading is taken. The second reading should be esssentially the same as the first; otherwise the instrument has been in motion while the readings were being taken, and the readings are erroneous. Because of its simplicity and because of the safeguard against erroneous readings, this type of drift indicator is the most commonly used.

A modification of the above instrument uses a disc of light-sensitive paper upon which an image is made by a hollow plumb bob and a light source. There is no provision for a second reading in this instrument, but the slow exposure speed of the sensitized disc is an assurance against erroneous readings. No image will appear on the disc if the plumb bob is in motion during the exposure.

The single-shot instrument is generally run at intervals as the hole is being drilled. In this way a check of the well's direction can be made about every hundred feet, and correction can be made if the well is not going as planned. As with the drift indicators, single-shot instruments are operated usually by the drilling crew. Normally a record of the angle and direction of drift is made by means of a simple camera which photographs on a disc of sensitized paper the image of a skeleton-type plumb bob, together with the concentric circles representing degrees of drift and a compass card. The angle of drift is indicated by the distance of the plumb-bob image from the center of the disc, while the compass bearing of the line from the center of the disc through the plumb-bob mark is the direction of drift. Most photographic single-shot instruments also have the protection that the slow exposure characteristic of the sensitized disc makes an erroneous reading improbable—a moving instrument will cause a blurred image on the disc.

Single-shot instruments are designed to be run in an empty hole or inside the drill pipe. As they are generally magnetically oriented, they cannot be used in a cased hole. The instruments for use inside the drill pipe are very popular and are designed either to protrude through the drill bit into the open hole where there is no magnetic influence, or to seat in a non-magnetic drill collar (K-Monel or similar metal). Both of these arrangements have the advantage that the instrument is held rigidly in place, and there is no possibility of a tilted instrument such as there might be in an open hole. The instrument run inside the drill pipe is retrieved by pulling it out with an attached sand line or by pulling up the drill string. The greatest advantage of these instruments that are run inside the drill pipe is that it is not necessary to make a round trip with the drill string in order to take a reading.

After the well has been completed, or before the casing is set at an intermediate depth, a multiple-shot survey of the entire well is frequently made. This method of well surveying has the advantage that a complete survey of the hole is made in one operation. The operation of the multiple-shot instrument in an uncased hole is essentially the same as that of the single-shot instrument, with the exception that the record is made on a roll of film which is advanced automatically after each reading is taken. Either the camera shutter and film-winding mechanism are operated automatically at a given interval of time by a clock mechanism, or a conducting cable is run from the instrument to the surface and the operation controlled by the operator. During the course of the survey the instrument is lowered to the bottom of the hole, usually on a wire line, but occasionally on drill pipe or tubing; then it is raised slowly to the surface, stopping at regular intervals, commonly every 100 feet, for a reading. The multiple-shot survey may also be taken with the surveying instrument lowered into position within a non-magnetic drill collar; and in this instance, readings are taken as each stand of drill pipe is removed from the hole.

Two methods have been utilized for making multiple-shot surveys in cased holes. As the drift angle from the vertical can be measured by means of a plumb bob in either cased or uncased holes, the only new problem in cased holes is determining the compass orientation of the drift direction. The first cased-hole method consists of noting the exact postion of a reference mark on the surveying instrument as the instrument is lowered into the hole on a string of drill pipe. The rotation of the drill pipe with respect to a fixed point is noted as each stand is added to the drill string. Surveying instruments are used to make accurate readings of the drill pipe rotation. The algebraic sum of the successive rotations of the drill pipe gives the orientation of the reference mark on the multiple-shot instrument at all times.

The second solution to the orientation problem in cased wells is through the use of a gyroscopic compass in place of a magnetic compass. This method eliminates the necessity of measuring drill-pipe rotation.

Multiple-shot surveys are customarily run by service company crews who are trained to run the instrument. Unlike drift indicators and single-shot instruments, multiple-shot instruments are not leased to drilling companies for operation by drilling crews.

Frequently a multiple-shot survey is run at the completion of a well as a double-check on the well course as determined by single-shot surveys taken during the drilling. If the calculated course and position of the well from each of the two surveys agree, the results of one of the surveys are taken as the true course of the well. The accepted survey is frequently the single-shot survey, but the engineer or geologist in charge may choose the multiple-shot survey if he believes it to be more accurate. If the results of the two surveys are in wide disagreement, another multiple-shot survey may be made of the well—frequently by a different service company using a different instrument—before one survey is accepted as correct.

TECHNIQUES OF DIRECTIONAL DRILLING

There are two basic types of directionally drilled wells: (1) after the maximum angle of deflection has been reached, that angle is maintained to the bottom of the hole; or (2) the maximum angle of deflection is maintained for a distance after it is attained, then the angle is decreased and the hole becomes closer to vertical or essentially vertical near the bottom. The techniques of drilling both types of wells are essentially the same except that more deflection tools and more care must be used in drilling the latter type. The normal sequence of steps in the drilling of a directional well will be outlined in the following paragraphs.

A written well proposal is prepared first, outlining the anticipated course of the well. The typical proposal includes the depth at which deflection of the hole is to start, the rate at which angular deflection is to be built up, the bottom-hole target for the well, and the maximum allowable deviation from the proposed well course. The written proposal is accompanied by a plat, an example of which is shown in Figure 32-1, which depicts in plan view and cross section the course which the well is expected to take.

It is best to drill vertically as much of the upper portion of the hole as possible, consistent with the necessity of starting to deflect the hole at such a depth that a uniform and gentle rate of angular increase may be maintained to the bottom of the hole. Vertical hole is drilled more cheaply and faster than

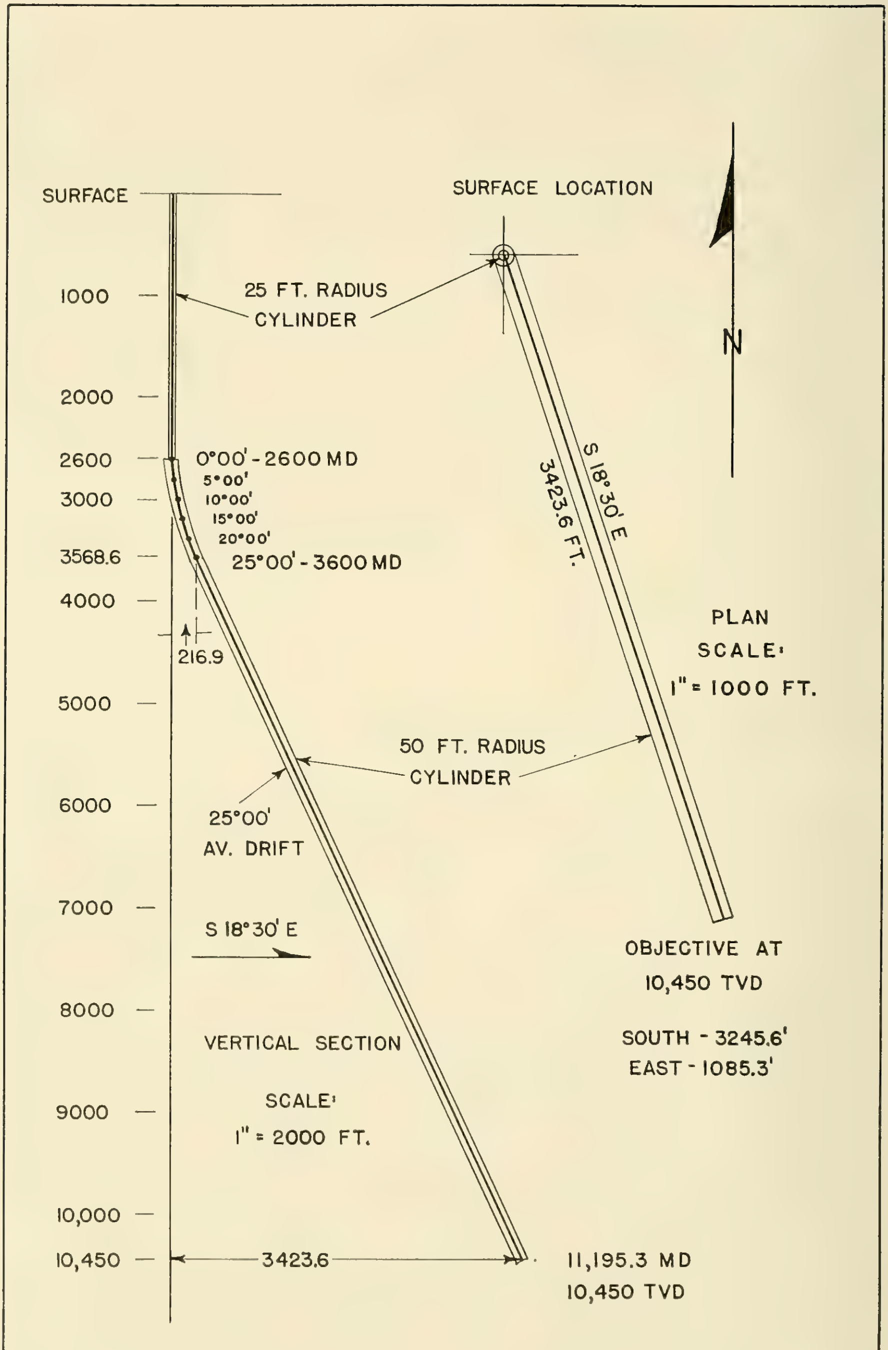

FIGURE 32-1. Idealized well proposal plat for directional well.

a directional hole, and costs of installation and maintenance of pumping equipment are less.

The "kick off" depth, or depth at which deflection of the hole is to begin, is chosen so that it is not necessary to increase the angular deflection of the hole by more than $2\frac{1}{2}$ degrees per 100 feet of hole. This depth is also such that the minimum deflection angle necessary to hit the target can be used.

It can be noted on the idealized well proposal plat, Figure 32-1, that both plan and vertical views of the well are given, together with the coordinates of the proposed bottom-hole target, and the true vertical depth and measured depth at various points along the well course. The vertical section is also marked with the points at which whipstocks are to be set or other deflection methods used. As the well is being drilled, the true course of the well is plotted beside the proposed course. Naturally there will be deviations from the proposed course which are unavoidable in the actual drilling of the well. It may be more practical, for instance, to set a whipstock a few feet higher or lower than planned in order to avoid making a round trip to replace a bit which is too worn to make the last few feet, or to avoid wasting the footage left on a bit which would be too worn to send back into the hole after setting the whipstock.

Other factors than the above also can cause minor deviations in the well course. The resistance and dip of the formations, and the pressure or weight on the bit must be taken into consideration. In order to set a limit on the allowable deviation, the directional-drilling proposal will usually set up a hypothetical cylinder around the proposed well and specify that the actual well must not deviate out of that cylinder. The radius of this allowable cylinder will vary with field conditions, but it will usually be within 25 to 100 feet. Difficult surface locations with other wells close by may require a smaller cylinder near the surface, but allow a wider target at depth, whereas a small reservoir target may require a cylinder which tapers to a small radius near the bottom of the hole.

During the course of a well, the actual control of the directional drilling is in the hands of a directional-drilling engineer employed by the service company which has contracted to supervise this phase of the drilling. The engineer, and through him the service company, is responsible for the drilling of the well within the limits called for in the drilling proposal. The engineer supervises the settings of whipstocks, recommends the type and number of drill collars and other weighting and stiffening members in the drill string, and he advises the drilling crew concerning the speed of drilling and the weight placed on the bit—all measures to insure that the well follows the plan intended.

The steps involved in setting a whipstock and beginning the deviation of a well from its previous course are pictured in Figure 32-2. The whipstock itself is a rather long tapered piece of metal which has a sharpened or chisel-like lower end. A special drill bit is attached to the whipstock by soft pins which are sheared by pressure exerted on them as drilling begins. Before the

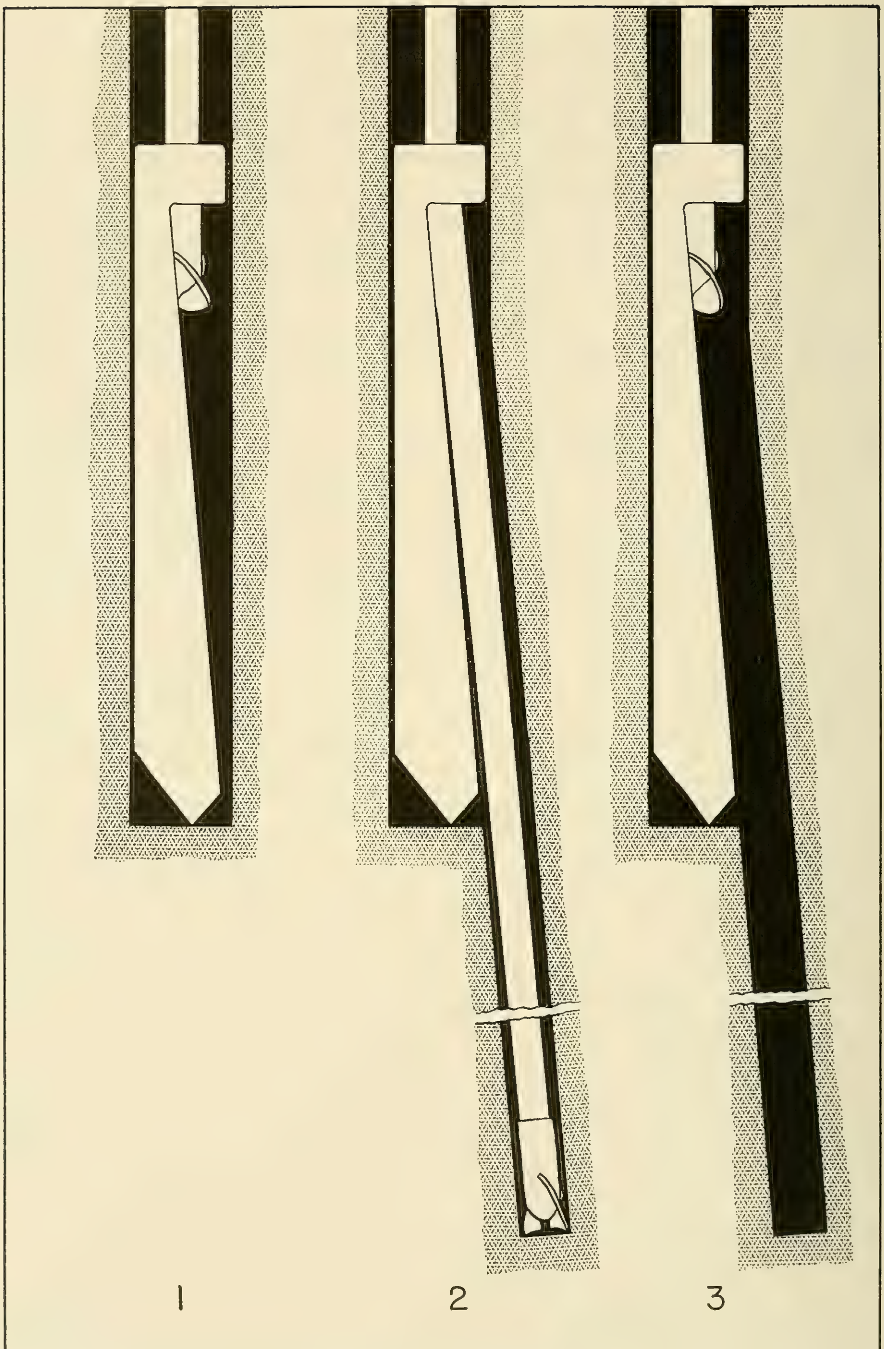

FIGURE 32-2. Generalized diagram of steps involved in deflection of a well by means of a whipstock. (1) Whipstock in place prior to shearing of pins holding bit to whipstock. (2) Drilling of first portion of deflected hole. (3) Pulling out of hole to remove whipstock—bit will not pass through the upper collar of the whipstock; hence whipstock is removed with the drill string (Modified after Murdoch).

actual setting of the whipstock, the hole is prepared by the use of a flat-bottomed bit that provides a firm base for the whipstock. The whipstock is run into the hole on a string of drill pipe, and orientation of the tool is accomplished by measuring the rotation of the drill pipe as it is lowered into the hole or by using a special drill sub with oriented magnetic plugs. Orientation of the whipstock by measuring the rotation of the drill pipe is identical to the procedure outlined under the use of multiple-shot instruments in a cased hole.

The bottom-hole-orientation system is used in holes which have more than 2 degrees of angle at the point a whipstock is to be set. Before this method is used, a single-shot or multiple-shot survey must be made to determine the drift and direction of the well at the point in question. The two opposite-pole magnets in the special drill sub are placed in exact alignment with the face of the whipstock before the tool is run into the hole. A special bottom-hole-orientation instrument is run into the hole when the whipstock has reached bottom, and a reading is taken. The orientation instrument is similar to a drift indicator, except that the recording disc is placed in a cup which is free to move and which is magnetized. The bottom-hole reading is taken when the instrument is between the magnets of the sub, and the instrument is read on the surface when it is placed between two magnets that have exactly the same relation as those on the sub. The angular relation between the face of the whipstock and the low side of the hole, as indicated by the plumb-bob image on the recording disc, is obtained; and the drill pipe is rotated the required amount to correctly face the whipstock. After the rotation of the drill pipe, the bottom-hole orientation instrument is run again to check the facing of the whipstock.

Once the orientation of the whipstock is known and the drill string has been rotated until it is facing in the desired direction, the whipstock is seated by gentle spudding (i.e., raising the drill string slightly, then allowing it to fall) which forces the chisel point into the bottom of the hole. When the whipstock is firmly seated, weight is applied to the drill bit, and rotation is started to shear the pins holding the bit to the whipstock. Drilling is continued with care until the taper of the whipstock forces the bit to one side and the well takes its new course.

After about 20 feet of new hole has been drilled, the drill string and whipstock are removed. Because the bit itself is larger than the opening in the upper collar of the whipstock, removing the bit also removes the whipstock. Care is taken in going back into the newly deflected hole, but once the round trip past the kick-off point has been made several times, there is very little tendency for the bit to miss the new hole. Figure 32-3 shows a whipstock that has been removed from the hole after successful deflection of the well.

The procedure for setting a removable whipstock outlined above is similar to that followed in drilling most directional wells; however, modifications of the above procedure sometimes are used. Some whipstocks are designed to remain in the hole and are not removed after deflection has been accomplished. In soft formations a knuckle joint, a coupling which holds the drill bit at an angle to the main drill string, may be used to drill sufficient hole so that a flexible drill string will follow into the deflected hole, and no whipstock is required.

FIGURE 32-3. Whipstock being removed from well after use (courtesy Standard Oil Company of California).

A special spudding bit may also be used to drill enough hole by spudding to allow the rotary drill string to follow into the deflected hole. Also in soft formations, a special jet bit may be used that is constructed so that a strong jet or stream of drilling fluid is directed against the side of the hole when the bit is facing in the proper direction. The force of the jet is sufficient to drill a hole at an angle to the main hole and allow a drill string to pass later into the deflected hole. This last technique also has the advantage that no whipstock is required, and it is thus cheaper and faster than the standard method in areas where it will work.

APPLICATIONS OF DIRECTIONAL DRILLING

Perhaps the most spectacular application of directional drilling to modern problems is in the drilling of a relief well to control a well that has blown out of control. Such a well which is spoken of as blowing wild, has frequently caught on fire and formed a sizeable crater around the surface well location. Well A in Figure 32-4 represents a typical well out of control. From location B a relief well is directionally drilled to intersect well A at a point shortly above the high-pressure zone which is causing the trouble. This surface location at B is far enough away from A so that the rig operations of the relief well will not be endangered by the wild well. Pressure-control materials then can be introduced through well B into well A and the well brought under control. The accurate drilling of such a well is a tribute to the ingenuity and skill of the directional-drilling engineers, particularly when the small size of the target to be hit is considered.

Other oil-field operations involving directional wells are usually less spectacular, but they are far more common and bring a much greater return to the well operator. At the present time in the United States much attention is being directed toward the search for oil on the continental shelf areas beneath the Gulf of Mexico and the Pacific Ocean. There are many engineering problems not encountered on land which have to be solved in order to exploit these off-shore reserves.

One of the prime off-shore problems is the establishment of a suitable foundation structure to accomodate the drilling rig and its attendant facilities. This problem is generally solved (1) by using a mobile drilling barge which can be floated to the location and anchored in place, (2) by constructing a platform which is supported by pilings anchored to the ocean floor, or (3) by building a man-made island in moderately shallow water. The elaborate self-contained drilling structures, which are currently being built by drilling contractors and oil companies for use in deep water, are essentially barges with retractable pilings or legs which can be let down to anchor the structure solidly on the ocean floor.

Each of the foregoing solutions to the off-shore location problem, with the possible exception of a shallow-water drilling barge which can be moved from one location to another with relative ease, involves a great deal more expense and labor than a similar on-shore location, and because of this fact, the maximum possible use must be made of each established off-shore location. Most of these locations are currently designed to accommodate a number of wells all drilled from the same surface location. The platform or island is usually so located that one of the wells is a straight hole. The remainder of the wells are directionally drilled to bottom-hole targets that are in accord with the established well-spacing pattern for the field. All the wells drilled from these off-shore locations are usually drilled with the same drilling rig—the derrick being movable, or the crown block and the rotary table both being movable.

Figure 32-5 illustrates a typical off-shore platform under contruction in the Gulf of Mexico. This derrick and platform will be used to drill 6 wells, 5 directional and 1 straight. The LST, which will be hooked up to the structure, will be used as a housing and maintenance unit for the drilling crew and as storage for drill pipe, casing, drilling mud, and other material.

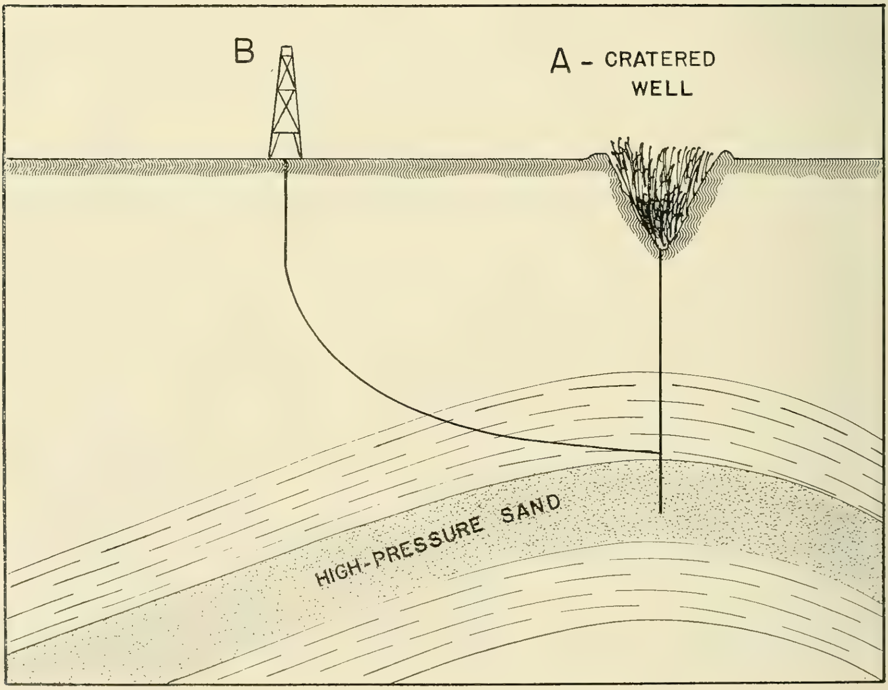

Figure 32-4. Directional drilling of a relief well to control a well which is blowing wild.

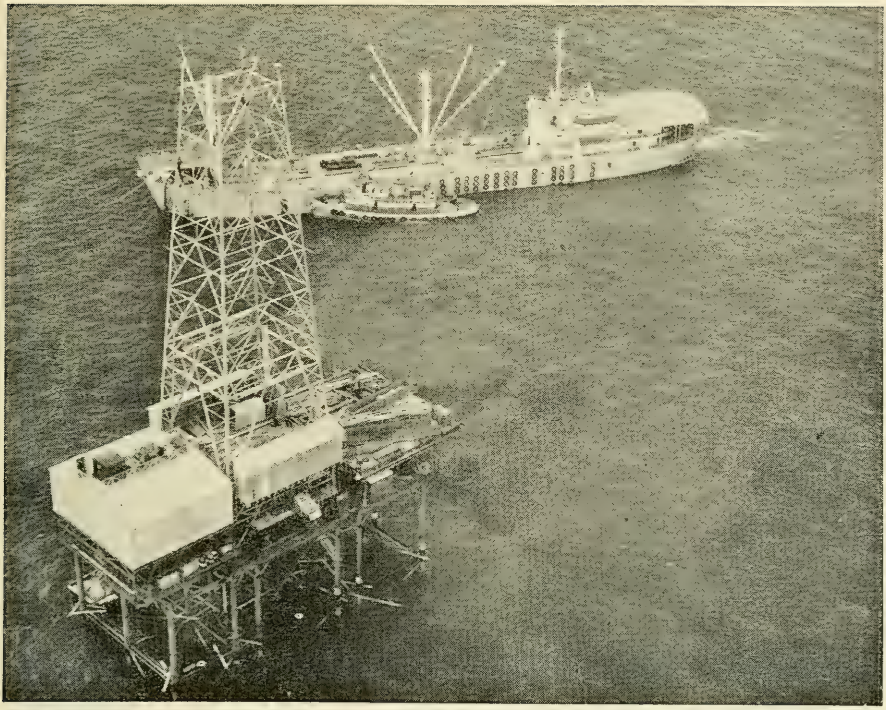

FIGURE 32-5. A six well derrick is shown being constructed atop a platform in the Gulf of Mexico. In the background, an LST is shown prior to hooking up to the structure to begin serving as a drilling tender.

In a number of areas, particuarly along the California Coast, it is not possible to utilize the conventional Gulf Coast type of off-shore platform because of the steepness of the slope of the continental shelf. Under the same conditions, it is frequently not feasible to construct man-made islands for well locations. The special well-location problems of these areas are presently under study, and several oil companies are testing or planning new types of off-shore drilling barges and platforms which will be suitable for Pacific Coast conditions. California law also restricts the type of exploratory and development wells which can be drilled in certain areas. Along some stretches of the coast, only on-shore drilling locations may be used, and no off-shore barges or islands are permitted.

Where a prospective or proved tidelands oil field lies reasonably close to the shoreline, the use of directionally drilled wells from an on-shore location solves many of the location problems of off-shore drilling. The well site is readily accessible and location costs are at a minimum. This type of drilling has been especially popular along the Southern California Coast. In fact, until 1955 it was practically the only type of off-shore drilling permitted in California

—the exception being some wells drilled from piers in the Ventura County area. The only condition under which an off-shore well could be drilled was in the case of an existing well draining a pool that extended onto State property. The Huntington Beach Field in Orange County, California, is a well-known example of this type of development. At Huntington Beach hundreds of wells have been drilled from closely spaced locations along the beach and have bottomed in the prolific reserves under the ocean.

Figure 32-6 illustrates one of the new wells which are being drilled from locations on the shore, but which will bottom under the ocean. This well, located near Montalvo in Ventura County, California, was drilled to develop a pool which extends from the shore outward under the Pacific.

Occasionally, in areas other than the tidelands, it is necessary to drill a well from a location which is not directly above the petroleum reservoir, because (1) the pool being developed is located under a residential area or other urban development and the factors of noise and zoning regulations must be considered; (2) the desired well site is under a river, swamp, or other natural obstacle

FIGURE 32-6. A typical on-shore location for a well which will bottom under the Pacific Ocean in the background. Location is in Ventura County, California (Courtesy Standard Oil Company of California).

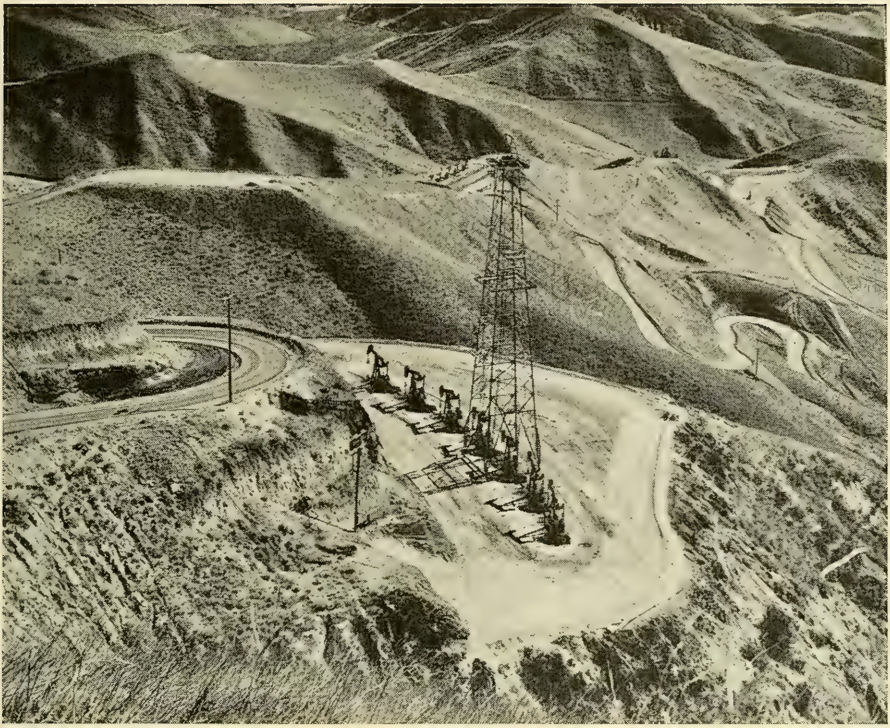

FIGURE 32-7. Well "island" in South Mountain Field, California. Because of rough terrain, wells are drilled on level shelves formed by slicing off part of a slope. By use of directional drilling, a series of well heads are located in a row with the wells angling off like spokes of a wheel. Some of the well heads are as much as 1000 feet, laterally, from the producing sand. The wells are serviced by the one production derrick which moves on a curved track (Courtesy Shell Oil Company).

where it is not possible to build a suitable location; or (3) the terrain is so rugged that suitable locations cannot be made with ease.

Zoning laws will frequently prohibit the drilling of oil wells within city limits or residential areas, and pools beneath these areas must be developed by drilling directional wells from outside the restricted area. The noise of drilling operations will sometimes rule out the possibility of drilling from a desired location even where not prohibited by zoning laws; however, modern techniques in sound-proofing drilling rigs and in designing and maintaining production installations are helping to relieve this problem.

Figure 32-7 is a photograph of a well "island" in the South Mountain Field in California. As can be seen in the photograph, the rugged terrain makes it necessary to drill and service the wells from level shelves cut into the mountainside. As many wells as feasible are directionally drilled from each shelf to develop as much as possible of the field and keep location costs down.

Geological problems, as well as location problems, create situations where directional drilling is the best solution. Faulting in an oil field is a continual challenge to the geologist assigned the task of selecting well locations. Figure 32-8 illustrates one of the many situations involving faulting that may be solved by directional wells. In this field the petroleum reservoir is in steeply dipping sands that are below a reverse fault. The fault itself is the seal for the reservoir. Because of the steepness of the beds, a vertical well, such as well B, would have to be located with extreme accuracy or it would penetrate only a very small portion of the reservoir. Such a well might conceivably miss the productive sands entirely if the sands are not thick. In any case, even a well-placed hole would penetrate only a small portion of the entire thickness of the sand above the oil-water contact. A directionally drilled well such as A, however, would have a far greater chance of penetrating a maximum productive section because of the greater vertical extent of the reservoir as compared to the horizontal extent. Furthermore such a well, even if poorly located because of scanty information about the reservoir, would have a greater chance of penetrating more of the effective thickness of the sand above the oil-water contact. A directional well in the reverse direction, such as C, might penetrate an even greater thickness of

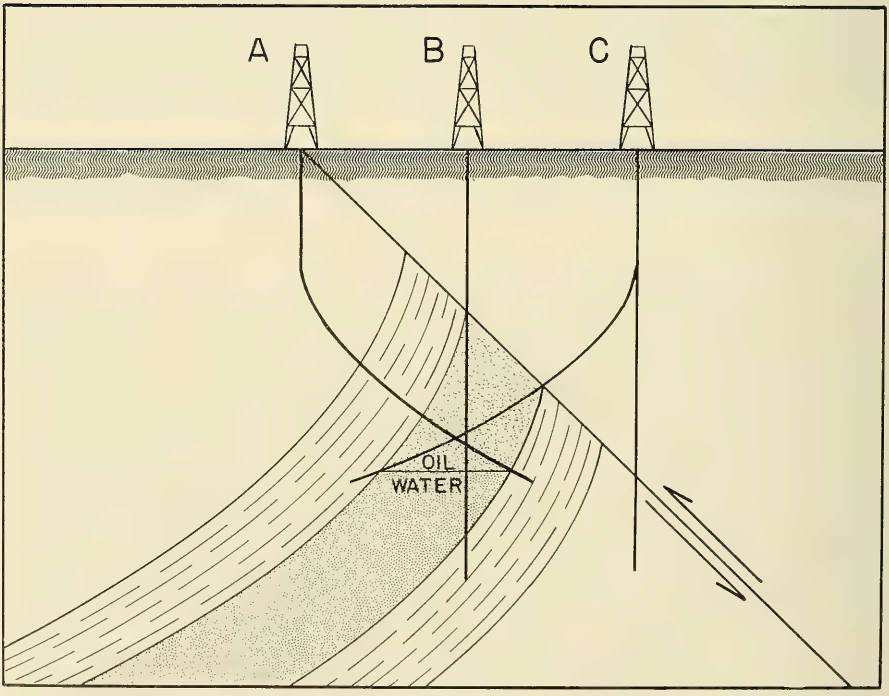

FIGURE 32-8. Controlled directional drilling for solving fault problems.

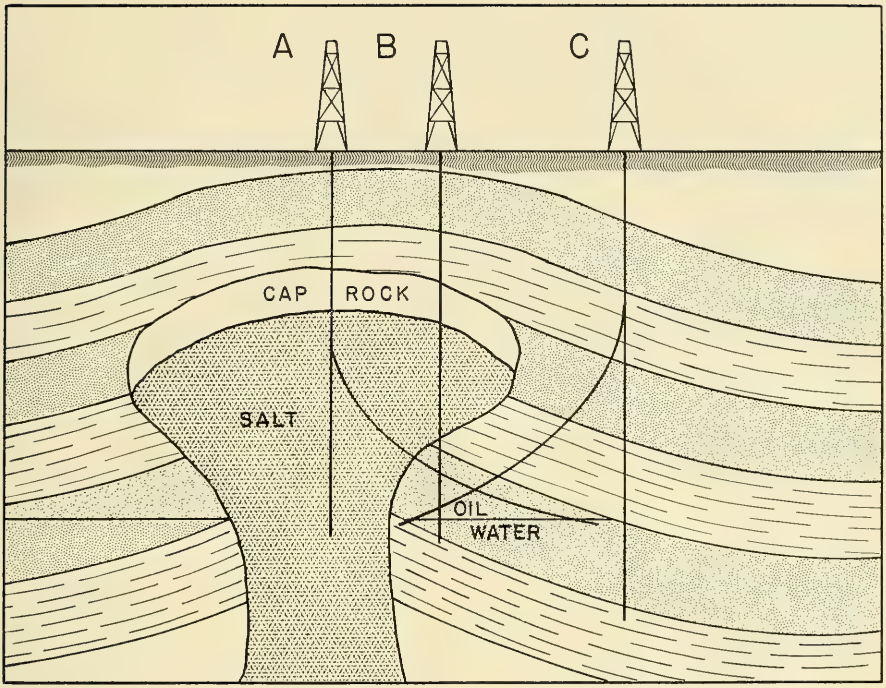

FIGURE 32-9. Development of flank oil production of a salt dome by the use of directionally drilled wells.

the producing formation. A straight hole at C which has missed the objective sand by penetrating the section on the wrong side of the fault might also be turned into a productive well by sidetracking and directionally drilling the well to cross the fault.

A final example of the applications of directional drilling is shown in Figure 32-9. Here a preliminary test well A has bottomed in salt after penetrating an unproductive section capping the salt dome. A second test well B on the flank of the dome has penetrated a productive zone after passing through the salt overhang. It may now be possible to go back into well A and sidetrack the hole—directionally drilling the sidetracked hole to tap the flank production. This procedure would save the cost of a new hole down to the sidetracked depth.

Inasmuch as drilling through the caprock of a salt dome is sometimes costly and difficult, it may be desirable, in the further development of this field, to avoid drilling through the salt overhang in order to reach the flank production. In this instance, directionally drilled wells may be used to reach the objective. Such wells may be allowed to lose drift angle and become vertical after passing below the salt overhang, or they may be drilled so that the well is parallel to the flank of the salt dome. In these ways a number of reservoirs at different depths along the flank may be penetrated.

The foregoing examples are only a few of the ways in which directional drilling is used in modern oil-well-drilling practice. Other applications are common in other oil provinces, and unique solutions are frequently applied to special problems.

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Chapter 33

CORE DRILLING

William M. Koch

When men began to delve into the earth for needed materials, it became apparent that they required samples to guide their search. The ancient Egyptians drilled into the rocks with tubular drills and secured short cores which aided them in the construction of the pyramids. Many centuries ago, the Chinese, when drilling water wells, performed a crude type of coring operation by driving hollow bamboo poles into the earth and then examining materials packed in the lower end. With the advent of the industrial revolution in the 19th century, many new devices for drilling bore holes and for coring were invented. A successful cable-tool coring device was patented in 1854; and in 1863 the first rotary-coring tool was designed.

In the early days of drilling for oil and gas, the cable-tool method was used widely. By this method, a drilling bit, which could be likened to a star drill, was pounded on the bottom of a bore hole to loosen the formation. When sufficient cuttings were produced, a bailing device was used to remove them from the bottom. The examination of these cuttings yielded information about the penetrated formation. Later on a cable-tool core drill was developed which encased a cylindrical core left by the drill. By raising the tool, a core catcher broke and retained the cored section. Originally in the rotary-drilling method, geologic information was obtained from the cuttings brought to the surface by the circulating fluid. Later a very simple type of coring tool was used which consisted of a joint of pipe with the lower end slotted to form teeth. This pipe, called a Texas type or "Poor Boy" core barrel, was fairly effective in recovering cores from the softer formations. To prevent washing away the core by circulation coming through the drill pipe, an opening was prepared in the side of the pipe a short distance from the anticipated level of the core. The opening permitted the drilling fluid to pass into the annulus of the hole. When the core was cut, the rotation of the barrel at high speed and at an increased weight caused the teeth on the bottom of the pipe to bend inward, cut off the core, and hold it in the barrel.

Today's highly complex coring bits and barrels are in considerable contrast to the earlier types. Drilling depths and other factors have made the cutting of cores a much more complicated and professional operation.

Core equipment can be placed in two general categories: (a) core-drilling bits, which cut a core and advance the main well bore at the same time, and (b) side-wall coring tools, which cut a core from the wall of a previously drilled bore. Core-drilling bits can be further classified as, (a) conventional core bits in which the cores are recovered by bringing the tool to the surface, and (b) wire-line core bits in which the core barrel can be pulled to the surface by a cable and another substituted without removing the drill string from the hole.

Side-wall coring tools also come in many types and can be classified generally into two main groups. The first type requires running of the drill string into the hole with a deflector shoe attached to the bottom. Coring tools that are then run on a wire line either drill or punch the core from the hole wall. Because the coring barrel is run on a wire line, the deflector shoe may be positioned at different points in the hole and successive cores taken where desired. The other type of side-wall tool is run on a wire line and has a device which punches a core from the side wall by means of a hollow bullet fired from a gun. Side-wall coring produces a relatively small-diameter core that penetrates only a short distance into the wall of the hole.

CONVENTIONAL CORING A modern conventional coring barrel is illustrated in Figure 33-1. This type of barrel can be used without special surface equipment because it is attached to the lower end of the drill string and run into the hole. After the core is cut, the drill string is pulled with the core barrel. As Figure 33-1 shows, the outer casing of the tool consists of a connection at the top which is attached to the bottom-tool joint and the barrel. The outer barrel is a tube connecting the drill string and the drill bit. The drill bit, consisting of a cutter-head body, is attached to the cutter-head crown. On the inside of the tool, the core catcher is positioned between the core barrel and the cutter head. Two different types of core catchers

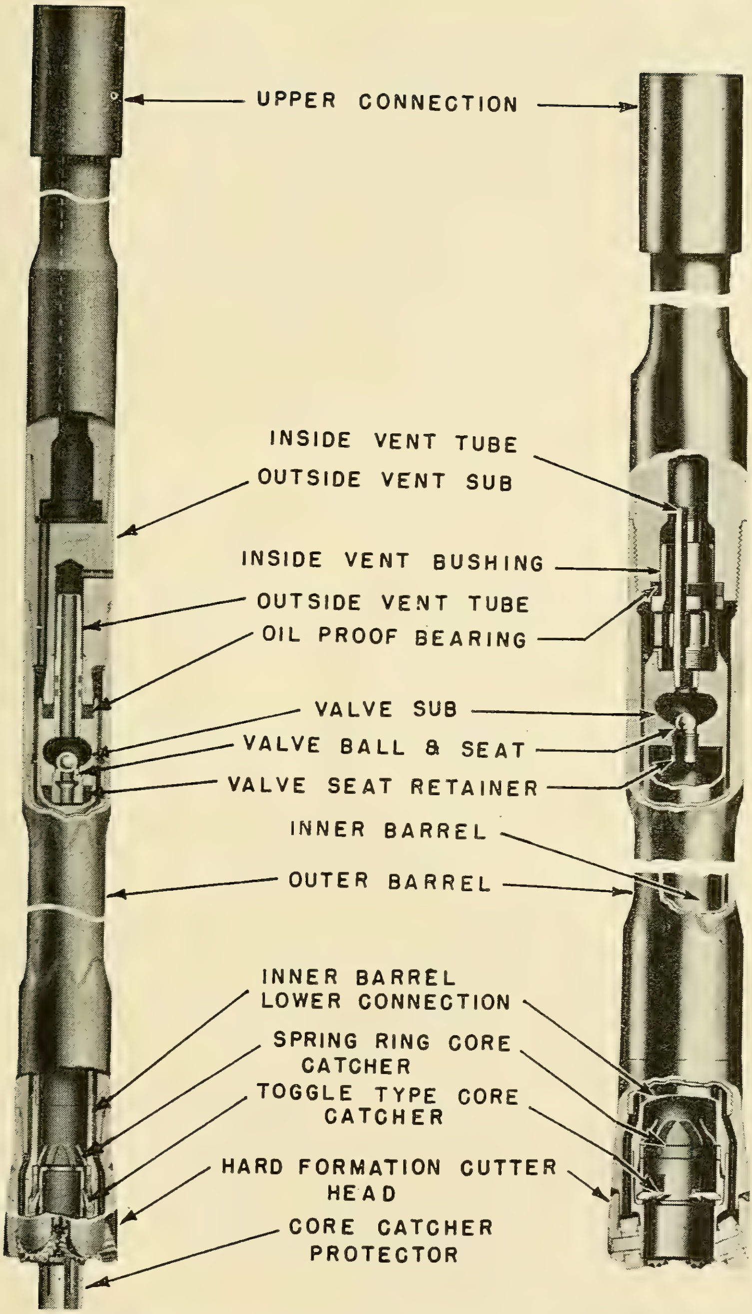

FIGURE 33-1. Conventional core barrels (Courtesy Reed Roller Bit Company).

are illustrated in Figure 33-1. The toggle type consists of alternate long and short fingers arranged to dig into it and break off a hard core. Above this unit is the spring-ring core catcher, consisting of flexible fingers that bear against the core. These serve two purposes: (1) they hold a broken core, or (2) if the core is soft, the fingers bite in, cut off, and retain the core. The inner barrel extends through the outer barrel to the bearing at the upper end which presses against the upper connection. The upper end of the inner barrel is a vent sub containing a check valve, which allows fluid in the barrel above the core to be pushed out as the core advances into the barrel. The upper part of the valve sub contains the upper bearing and ports which allow the circulating fluid coming down through the center of the upper connection to pass into the annulus between the inner and outer barrels and flow to the drill bit. As the core is pushed into the upper barrel, the force on the inner barrel is generally upward. The rubber bearing at the top permits this load to be transferred to the upper connection with minimum drag on the inner barrel. This permits the inner barrel and the core catcher assemblies to remain stationary with the core while the outer barrel and the cutter head rotates. The elimination of motion by parts in direct contact with the core prevents breaking up of the core, thus materially increasing the percentage of core recovery. After about 18 feet of section has been cored, rotation is stopped and the drill string raised. This causes one or the other core catchers at the bottom to engage the core, break it off, and block its passage out of the barrel. The drill string then is pulled and the core barrel brought to the surface, where the core is removed.

Some variations of the conventional core barrel are the outside-vent core barrel, the drop-ball type, and a combination of the outside-vent and drop-ball. Since the check valve in the upper end of the core barrel opens into the interior of the core barrel, the fluid passing through the check valve must overcome the pressure of the circulating fluid at the top of the barrel. In soft cores the additional load on the core might cause it to swell and stick in the barrel, thereby preventing additional core entry. One way of combating this situation is to use an outside-vent sub, which is a special section inserted between the outer barrel and the upper connection. This sub then allows the fluid from the inner barrel to be vented to the exterior of the barrel where pressure is lower. This outside-vent core barrel allows the fluid above the core to be much more easily displaced, thus facilitating the cutting of very soft material. When the barrel may become clogged with contamination on the way down, or when it is necessary to flush the bottom of the bore hole very strongly in order to clean it of junk, the standard barrel may be used as a drop-ball type. The valve ball and the vent tube (fig. 33-1) are removed when the barrel is run and before coring operations are started, mud is circulated through the barrel to clean it as well as to flush the bottom of the hole. Then just prior to coring, the ball is dropped through the drill pipe and seats at the top of the barrel.

A special application of the conventional-type core barrel is encountered in drilling for sulphur. The problem of the driller, in attempting to reach the deposit, is comparable in many ways to those of the oil driller; however, in some respects sulphur drilling is more complicated. Sulphur is found in dome structures, but there is no definite means of predicting whether a given dome will contain sulphur that is recoverable. This can be determined only by continuous coring. Core recovery of sulphur is very difficult because the element occurs in a calcium sulphate matrix which is brittle and easily fractured. Therefore, it is advantageous to cut as large a core as possible so that the core will be strong enough to withstand drilling stresses. Figure 33-2 shows a conventional-type core barrel especially designed for sulphur coring or for coring other frangible deposits. The core size of this barrel is as large as possible for the size hole being drilled. The thin cutter head requires eight cutters rather than the ordinary six.

The thin cutters permit the head to run more smoothly, thus minimizing core breakage. To further facilitate the entry of the frangible cored section into the inner barrel, the barrel is supported on a special two-way rubber bearing at the top in order to secure the barrel in both directions and to allow it to float freely with the core during drilling operations. Since the sulphur-anhydrite mixture is relatively firm, a slip type of core catcher is used that consists of long fingers, with a tooth at the lower end, which fit into a tapered section in the head. The spring fingers, projecting in a spiral pattern on the inside of the core catcher, ride on the core and bend the fingers so that they are in close proximity with the core. When the coring operation is completed, the drill string is raised, and the teeth in the core catcher immediately dig into the core and wedge into the taper in the cutter head. This action breaks off and retains the core. The force to do this, which is considerable in a large-diameter core, is taken directly by the cutter head, thereby protecting the thin inner barrel and the bearing assembly.

Figure 33-3 illustrates several types of cutter heads. At the top is a standard-type diamond-core bit. The cutting surfaces consist of a multitude of industrial diamonds set in a tungsten-carbide matrix. Suitable grooves are provided to allow the circulating fluid to cool the cutting edges. This type of bit, although expensive, can be used economically in coring very hard formations. It may last ten times as long as a regular alloy bit. Core recovery is excellent because of its smooth-running action and the large diameter core that it cuts. The principal disadvantages of this head are the substantial loss that is possible if the bit fails prematurely, and the inconvenience and expense of the extra long conventional core barrels that are needed to take advantage of the bit's potential life without excessive round trips. The center illustration in Figure 33-3 is a roller-type coring bit, normally used in medium-hard formations. This core bit consists of six cutters, three of which cut the bottom and the wall of the hole,

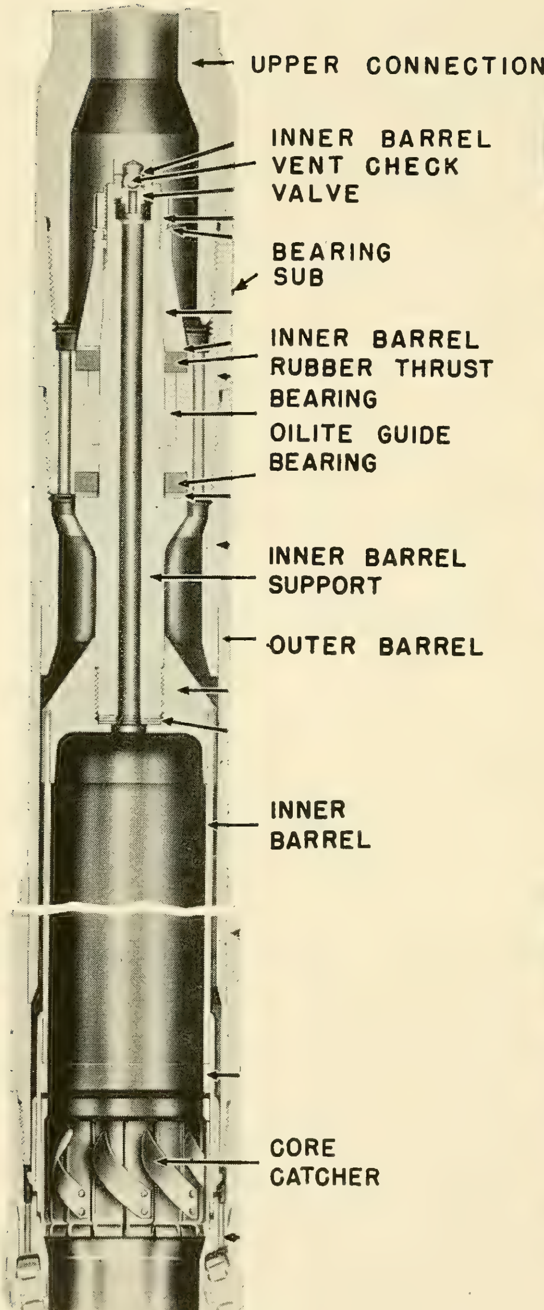

FIGURE 33-2. Frangible formation core barrel.

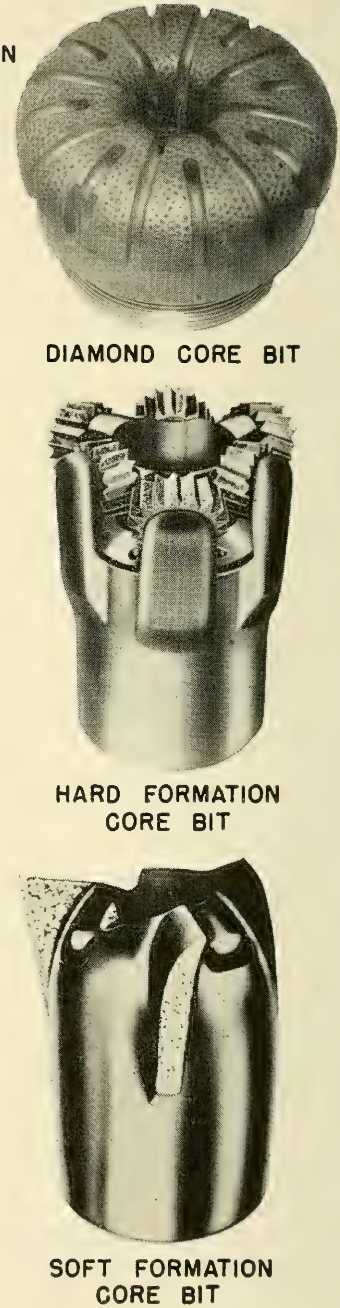

FIGURE 33-3. Types of coring bits (Courtesy Reed Roller Bit Company).

and the other three cut the bottom and leave the core. The short cutter assembly is welded to a sub that contains the threads and fluid passages. This cutter assembly can be interchanged with a bladed-crown type for coring soft formations (bottom illustration of fig. 33-3). The blades of this bit are coated with tungsten carbide to provide more abrasion resistance.

WIRE-LINE CORING

Early in the use of conventional core barrels, two inherent difficulties stimulated oil-field equipment personnel to design a coring device that could be brought to the surface without pulling the entire drill string from the hole. One difficulty was that in easy penetration, the entire string would have to be pulled to the surface when the core barrel was filled, even though the bit was capable of further penetration. The second difficulty arose when, during regular drilling operations, an interesting strata was encountered. The inconvenience of pulling the entire drill string in order to run in a core barrel before the bit was dulled often resulted in by-passing a critical core.

The wire-line coring and drilling equipment was devised to overcome these difficulties. In this type of core barrel (fig. 33-4), a drill bit that leaves the core in the center is attached to an outer body or drill collar, and the core barrel is dropped into the assembly. The core barrel is generally of the protruding type and sticks through the center of the bit, thus penetrating ahead of the bit cutters. This type, which is mounted on a spring arrangement that allows the head to float in and out, drills ahead of the main bit in softer formations and retracts into the main bit when hard formations are encountered. When coring is completed, an overshot is lowered through the drill pipe on a wire line, hooks onto the barrel, unlatches it, and pulls it to the surface. If drilling is to be continued without taking cores, another barrel equipped with a center bit is used. This bit drills up the core left by the drilling bit. By this means, the main bit can remain in the hole as long as it is sharp, and as many cores may be taken as are desirable. If a core is not needed, the center bit allows normal drilling to proceed. However, at any time, the center bit may be quickly pulled out and the core barrel dropped in place to accommodate unexpected drilling breaks.

As Figure 33-4 shows, the upper part of the barrel consists of the driver sub whose upper end carries a conventional tool-joint thread attached to the drill string. On the lower end a special pin thread connects the main barrel. On the inside of this pin is a special box thread that holds the core-barrel driver. The main outer barrel is connected to the driver sub and connects at the lower end to the drilling bit. The drilling bit may be either a hard-formation type with rolling cutters or a soft-formation bladed type. The wire-line barrel is dropped into this assembly. The lower part of the barrel contains the cutter head, which trims the core to the size of the barrel. Inside this head is a core

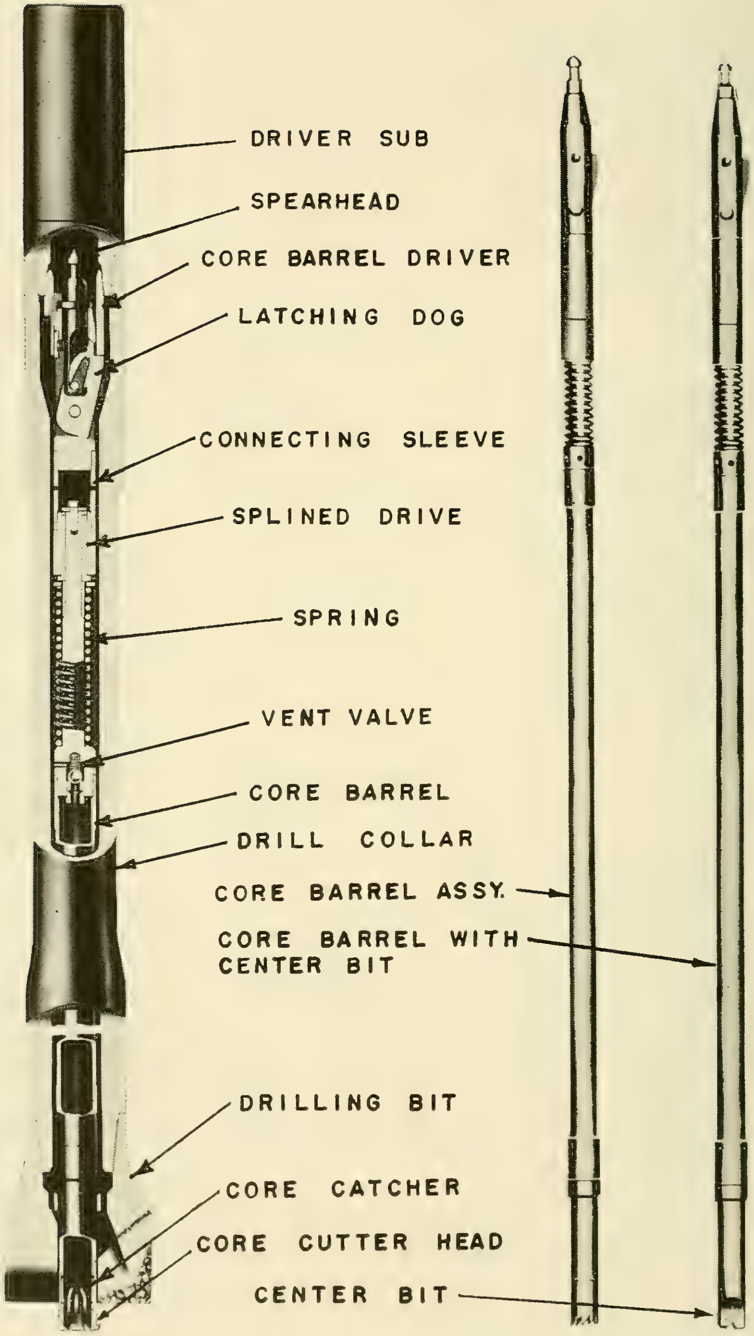

FIGURE 33-4. Wire line core barrel (Courtesy Reed Roller Bit Company).

catcher to which several types may be fitted. The barrel extends up through the slush ring in the bit, and on the upper side it has an enlarged diameter. The slush ring prevents the barrel from protruding too far through the bit. At the upper end of the barrel is a spring-valve body or check valve to vent the interior of the core barrel of trapped fluid. This spring-valve body is keyed to the upper part of the slip joint, and the barrel spring is between these parts. The keys transmit the rotary driving power to the lower core barrel but permit the core barrel to move up and down, compressing the spring. This feature which allows the main core barrel to drill ahead of the main bit, cuts the core and encloses it in the barrel before it becomes contaminated or washed away by the drilling fluid. This arrangement is necessary because a smaller core must be cut so that the barrel will pass through the collars and tool joints of the drill pipe. The smaller core is more susceptible to damage than a larger core; therefore its recovery factor becomes even more important than usual. Above the spring-valve body is the carrier body and an assembly containing the latching device. In this device, a retractable latching dog protrudes when the barrel is in position and engages the core-barrel driver, which is mounted in the end of the upper sub. A finger holds the barrel down and forces it to rotate. The retractable latch dog is connected to the spear head. When the barrel is to be removed from the bit, the overshot is run down the pipe to the barrel spear head. Two overshot dogs latch over the spear head, and when the overshot is raised, the spear head moves up and retracts the dog, thus freeing the barrel and allowing it to be drawn to the surface.

A variety of core catchers may be fitted to wire-line barrels. The basic type is a spring-ring core catcher with one- or two-length springs that are fairly stiff. For soft sand formations, a multi-leaved, very flexible spring-core catcher is used. This type closes off completely. Either of these types of core catchers may be installed in tandem. For very hard cores a slip-type core catcher is installed. It has long flexible fingers that engage the core. When the barrel is raised, it will slide down the taper on the inside of the cutter head, nip off the core, and hold it firmly for raising to the surface. Various types of the wire-line core bits will cut cores ranging from 1 to 2 3/16 inches in diameter. The size of core is governed by the size of the drill pipe through which the core barrel must be dropped. For regular $4\frac{1}{2}$ full-hole tool joints, a $1\frac{5}{8}$-inch core is possible. The core barrel will cut cores from 6 to 10 feet in length. If longer cores are desired, the barrel may simply be replaced and coring continued.

Several points must be watched when this type of equipment is used. The recommended routine for preparing the tool should be followed closely. At least two inner barrels should be adjusted to fit the outer barrel and bit so that time will not be lost in the coring operation. The inner barrels are checked for latching and protrusion after they are dropped into the outer barrel. The protruding end of the barrel is rotated until it latches; then the protrusion of the cutter head is checked with the barrel pushed against the stop. If the core-cutter head does not stop within a quarter inch of the adjacent bit tooth, the protrusion may be adjusted by inserting washers under the retracting spring-retaining bolt. The outer barrel and bit are then run in the hole several pipe stands, and the core barrels are dropped into place and retrieved to make certain all is in proper working order. In this operation, one must be sure that the bit and outer barrel are submerged in the drilling mud, because dropping a core barrel into a dry tool may damage the landing ring. If the hole is caving or full of contamination, a core barrel equipped with a center bit is put into the tool when it is run in the hole. After the bit is run into the hole, it is stopped three or four feet off bottom and the center bit is retrieved. The kelly is attached and the tool is circulated for 10 or 15 minutes to clean the barrel and the bottom of the hole. The connection then can be broken and the core barrel dropped. It can be allowed to fall freely, but it is usually faster to connect the kelly and to pump the barrel down. When it seats properly, as indicated by an increased mud pressure, the core barrel is latched by rotating it slowly and feeding the bit to the bottom. It is rotated for a minute with enough weight to retract the core barrel; then it is lifted off bottom and lowered again. Coring can then be started. If at any time during the coring operation the drill string must be raised, as when making a connection, the core barrel is pulled and coring is resumed with a new one after the connection is made.

Another occasion for changing the core barrel arises in coring broken sand and shale. As soon as a shale streak is penetrated, a new core barrel should be substituted to prevent loss of the sandy core, because this core probably would not be sufficiently strong to push the sticky shale up the barrel. Upon completion of coring, the core is detached by raising the bit off bottom. In very hard formations, extra weight and rotation may be necessary to break the core cylinder. Before the core barrel is retrieved, the tool is circulated for 10 or 15 minutes to clean out any material that might jam the barrel. After latching onto the barrel with the overshot, one should not pull the assembly to the surface too rapidly, because of a swabbing action that might pull a soft cored material from the barrel. If the core barrel cannot be retrieved from the tool, the overshot is released by letting the trip tube slide down the hoisting line and opening the latching dogs. The overshot then can be equipped with a jar to break the core barrel loose. The jar should be used at all times when coring in deep wells.

Wire-line barrels also have been furnished with diamond cutting heads. In this instance, however, a seating-in head-type barrel is used because a formation suitable for diamond drilling is too hard for a retractable barrel to work satisfactorily. Other specialized uses are made of the wire-line equipment. Special surveying tools are mounted on dummy barrels and dropped from the drill string. These tools protrude through the cutting bit and are able to measure such things as magnetic field strength without the shielding effect of the surrounding drill pipe and collars. High-pressure formation testers also have been made to drop into place in the wire-line barrel in order to obtain pressure samples of producing formations. Modern wire-line core barrels have been made into extremely versatile tools which are particularly adapted to taking continuous cores in soft and medium formations.

Although conventional and wire-line core barrels differ in operational details, the same general considerations apply to both types. In the process of coring, the principal object is to drill the hole and, at the same time, to obtain a clean unbroken core. Commonly a core will break into sections, sometimes quite thin. This breaking complicates the job of retrieving. Drilling should be done at moderate weights that are sufficient to make the bit penetrate. The weight must be limited to minimize any vibration or jarring, which tends to break and shatter the core. The core barrel must be straight to prevent the bit from gyrating, and for the same reason, the drill pipe just above the barrel must also be straight. It is bad practice to lift the bit off bottom, then go back and resume coring. This procedure causes the core catcher to break the core, and it can jam easily and prevent additional core from entering the barrel. Careful operation with both types of core barrels will insure the maximum recovery of core even in difficult formations.

SIDE-WALL CORING

The foregoing discussion has treated methods of taking of cores by tools which drill as cores are being taken. However, the operator may wish to secure a core *after* drilling has been completed. Either the subsequent logging procedures have indicated a core point that was overlooked originally, or the operator might have elected to drill ahead to total depth, then log and core the well. This type of coring involves side-wall coring, that is, the cutting of a core from the side of the well bore after the hole has been completed.

Wire-Line Punch-Core Tool

Figure 33-6 illustrates a wire-line punch-core tool. It consists of an outer body which is run in the hole on a regular drill string, and an inner barrel which is lowered on a wire line. The inner barrel consists of an upper latching device, a center section with an orienting device, and a hinged core barrel at the bottom. The tool is positioned at the proper depth; the kelly is set to one side; and the barrel is lowered on a wire line. Upon reaching bottom, the deflector on the lower part of the body deflects the core tube, which has been held straight by small shear pins so that it bites into the wall of the hole. The operator then carefully lowers the drill pipe to permit the core tube to swivel

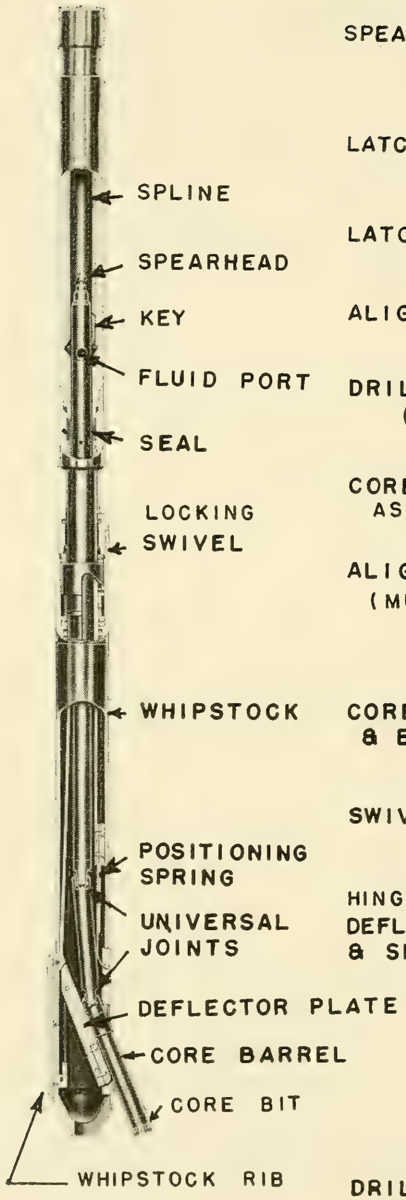

FIGURE 33-5. Rotary sidewall coring tool (Courtesy A-1 Bit and Tool Company).

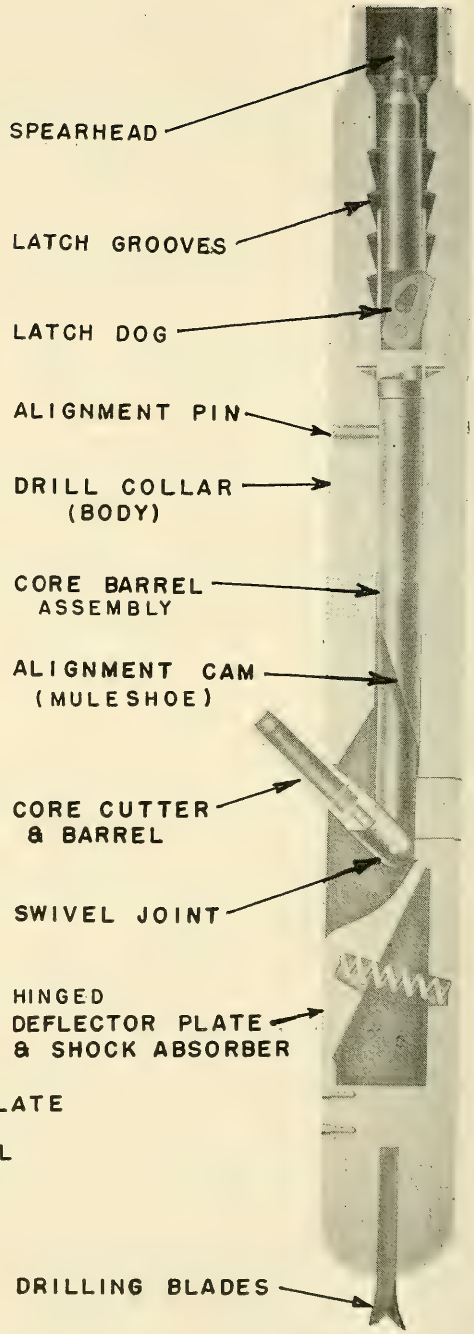

FIGURE 33-6. Wire line sidewall sampler (punch core) (Courtesy Houston Oilfields Material Company).

farther to the side and penetrate the formation. During this operation, if the weight on the tool exceeds 30,000 pounds, the core barrel may be damaged. In softer cores, the weight may not be apparent, and the operator must put a reference mark on the drill stem and lower it not more than $2\frac{1}{2}$ or 3 inches. This procedure permits the core barrel to punch a core out of the side wall. The pipe then is lifted, and the core barrel returns to its original position. The core barrel now may be recovered by an overshot on the wire line. The body then can be positioned at a different depth and another core barrel run to take a new core. This tool must be used on formations that are not too hard because the cores are taken by main force; however, a core can be taken in formations in which a rock bit will penetrate at a rate of 2 or 3 feet an hour. The obtained cores are $1\frac{3}{8}$ inches in diameter in the larger sizes and $1\frac{1}{8}$ inches in diameter in the smaller sizes. They are from 4 to 6 inches in length, which is considered generally to be long enough to penetrate the wall cake and the invaded zone at the side of the hole, and to secure a typical sample of the formation.

This procedure of side-wall coring is somewhat obsolete due to several inherent difficulties. It is a slow method because it requires the deflecting body to be run in on a drill string with the consequent expense of round-tripping. The core barrel is subject to damage when used in hard formations. Finally, the core barrel penetrates formations by pivoting around a hinge point. This action cuts a curved core that is forced into a straight tube, thus causing distortion and cracking that frequently reduces the value of the sample.

Rotary Side-Wall Coring Tool

A more recent tool, the rotary side-wall coring device, is shown in Figure 33-5. This tool, which is not limited to formation hardness, produces a larger and longer core than other types of side-wall coring mechanisms. As shown in Figure 33-5, these improvements were obtained at the cost of considerable complexity. The upper part of the tool rotates and drives the core barrel with the internal splines. A seal below the splines prevents mud flow past the coring barrel. The lower end is attached to the whipstock section by a set of swivel bearings that permit rotation of the drill pipe without turning the whipstock. The whipstock has an enclosed body with a window through which the deflector plate guides the core barrel into the formation. A fluted shoe mounted on the outside of the body opposite the window is selected to make the assembly fit snugly in the bore hole. The core barrel is dropped into the bottom hole assembly from the surface and is retrieved with an overshot on a wire line. The overshot latches onto a spear point at the top, which in turn retracts the driving key and permits the barrel to be raised. The core barrel is rotated by turning the drill pipe so that the splines in the upper body drive the core-barrel key. Since mud circulation is prevented from flowing past the barrel by the seal, it is diverted into the inside of the core barrel through a port in the side of the barrel. The cutter head and inner core-barrel section is connected to the top of the core barrel through universal joints that rotate the cutter head even though it is deflected out through the window. A hose conducts the mud flow through the joints to the lower section. The inner core barrel in the lower section is equipped with the usual vent valve and core catcher.

Preparatory to taking a core with this equipment, the bottom-hole assembly is to run into the hole to a point below the deepest coring point. A dummy barrel containing a wash nozzle is latched in place to keep trash out of the assembly during the run. The dummy is retrieved after the body has been washed clean. At this point, the minimum pressure for minimum circulation is determined. After the bottom-hole assembly is positioned at the proper point, the drill string is suspended in the slips, where it remains until coring is completed. A circulating head is attached to the drill stem because circulation must be maintained while rotating. The core barrel is pumped down and, when seated, rotation is started with minimum circulation. After a short run-in, coring is carried on at a speed of 18 to 25 revolutions per minute, and enough circulation is provided to maintain mud pressure at 200 to 250 pounds per square inch above the minimum pressure. This hydraulic pressure drop through the core barrel results in an axial load that supplies the force to feed the cutter head into the formation. The core is cut from the wall at an angle of 20 degrees to the main bore. When the barrel is fully extended, the circulation port in the core barrel passes through the seal, by-passing the mud flow. The resulting drop in pressure indicates the completion of coring, and circulation should be stopped immediately. When the core barrel is retrieved by the overshot, the core catcher breaks and holds the core. A resettable jar in the overshot permits repeated jarring of the core barrel if it should be difficult to pull out of the formation.

This tool is equipped with several safety features. If the core barrel cannot be pulled out of the formation, the overshot can be released and the barrel extracted by raising the drill stem. The deflector plate will shear a pin and pivot to make space for the core barrel. If the whipstock sticks in the hole, the drillable fluted shoe can be sheared off, or a heavy tension can be applied to the string to shear a pin in the swivel, allowing dogs in the rotating section to mesh with the whipstock so it can be positively rotated. If it becomes necessary to increase circulation while coring, a momentary application of high mud pressure will shear a pin in the barrel and open an additional fluid port, which will permit increased circulation at the same pressure.

This tool can drill a relatively large core, 1¼ inches in diameter by 12 inches long, in any type of formation. Cores can be taken at any selected level during one round trip of the drill stem. This unit is used successfully all over the world, but it is slower and more expensive than some other coring methods.

Percussion Side-Wall Coring Tool

Another important method of securing side-wall samples is the percussion or explosive-charge side-wall coring tool. A close-section view of this type of side-wall sample-taker is shown in Figure 33-7. Hollow bullets fit into short gun barrels in the body of the tool and are driven into the formation by powder charges. The cutting edge on the front of the bullet is designed to permit penetration of hard formations without shattering the core. When a bullet has been fired, cables anchored to the body pull the bullet and its core from the formation when the tool is raised. The projectile then hangs at the end of its cable out of the way of the other charges. The tool contains up to 30 shots that can be fired in sequence from the surface. The electric circuit that fires the charges is equipped with devices that determine whether a misfire has occurred. The

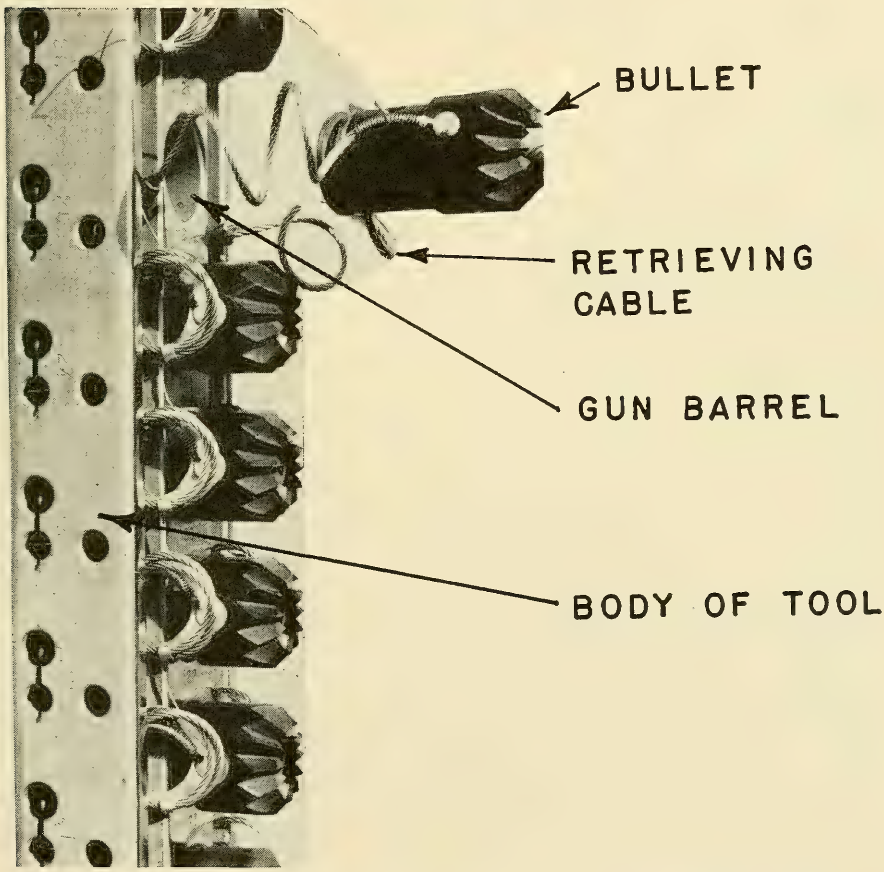

FIGURE 33-7. Sidewall sample-taker (Courtesy Schlumberger Well Surveying Company).

FIGURE 33-8. Sample-taker bullet and cores (Courtesy Schlumberger Well Surveying Company).

fact that the tool is run in the hole on a standard multiconductor cable used in electrical logging, permits a simple but positive method of locating the coring point. A logging electrode is run adjacent to the sample taker, and the coring point is determined by monitoring the electric log. Because the choice of coring points was determined with reference to the original logs, it is a simple matter to pick up any selected point independent of the actual depth of the tool. The complete operation consists of running the tool to a selected point for coring, firing a charge, then hoisting the tool to the next point.

Another view of the bullet and examples of retrieved cores are illustrated in Figure 33-8. This style of bullet, which produces cores 1 3/16 inches in diameter and up to 2¼ inches long, will penetrate most sedimentary formations. These cores can be subjected to regular core analysis for oil saturation, porosity, and permeability. In fact, such analysis represents a majority of the work done by Gulf Coast laboratories. In softer formations, the cores yield acceptable porosity and permeability determinations, but the tendency for them to shatter makes results unreliable in harder formations.

Since the explosive sample-taker was introduced in 1936, it has become increasingly popular because of its economy of operation. The hard-rock model has greatly extended the application of the tool because it will core most formations and will secure a sample of sufficient size for evaluation. It is run by the regular electric-logging unit and can obtain 30 samples from a 10,000-foot well in about 2 hours. Other more expensive side-wall coring methods are used only if this tool fails to produce desired results.

Chapter 34

APPLICATIONS OF CORING

H. L. Landua

In the past it has been found that coring is an aid in the solution of some of the problems in the geology and development of oil fields that may arise when subsurface formations are prospected. These problems are usually general, or they may be related directly to either exploratory drilling or field or proved-area drilling. The geologist must evaluate the formations pentrated by the drilling, and to do this adequately he usually utilizes the best tools and methods available.

General geologic problems usually result from a well condition in which a desired tool or method cannot be used. For example, frequently it may be desired to obtain an electric log of a well, but the circulating fluid in the well may be such that the logging instrument cannot function properly; or, because of sloughing formations or other hindrances, the condition of the hole may be such that the instrument cannot be lowered to the desired depth. Also, in many areas, the geologist prepares a formation-sample log from data obtained by examination of formation cuttings. At times, however, these cuttings may not be satisfactory because (1) mud-circulation rates may be too low to get them to the surface without their being reground; (2) the presence of caving or sloughing formations may mask the drilled cuttings; or (3) the formation cuttings may be so soft that disintegration occurs before they reach the surface. In such circumstances coring, even though possibly less desirable, would provide a means of obtaining substitute data for geologic use.

In exploratory geologic work the geologist may use coring and core-analysis data to (1) obtain a detailed formation description of the beds that are penetrated, (2) determine the dip and direction of dip of formation beds, and (3) determine the probable fluid content of prospective pay sections. After a core has been obtained and removed from the well, it is usually laid out in the same linear position it held in the core barrel so that the recovery amount and the formation depth can be recorded. By visual examination and measurement, a detailed description of the core is made, the formation composition, the texture, the probable geologic age, the dip of formation beds, and the probable fluid content being observed. If indications are that the core may contain oil or gas, further field and laboratory tests are usually made. Should a core contain oil or gas, the visual examination can usually determine only what section may be a potential producing zone. A special coring method must be used to determine the direction of the dip of formation beds, and obviously such a determination may be very valuable in locating the probable direction in which a structure may be located.

Field or proved-area geologic problems usually resemble those encountered in exploratory work to some extent. The principal difference is that proved-area geologic work generally is directed toward obtaining data that may be used to evaluate a known pay zone or to locate a formation marker. When an exploratory well encounters an oil- or gas-bearing zone, the geologic problems then resemble proved-area problems. In proved areas, the geologist may use coring and core data to aid in (1) determining the amount of pay section present, and (2) estimating the amount of oil and gas in place.

CORING IN RELATION TO PRODUCTION WORK

Frequently coring and core data can be used to an appreciable advantage in production operations and petroleum-engineering work, in addition to helping the geologist with his various problems. Probably the greatest use of coring in production work is for determining zones that should be formation- or production-tested and for determining, if possible, the gas-oil and water-oil contacts in those zones. Also, at times in production operations, it may be desirable to make an open-hole completion; that is, one in which the oil-string casing is set above the pay section to be tested and produced. Coring can be used to aid in determining the presence of undesirable upper sloughing shales and water-bearing zones immediately above the pay zone. The casing seat may then be picked at a point that would shut off the undesirable formations and yet allow the entire desired section to be tested. Information about the texture of the formation in a prospective pay zone usually aids in picking the most desirable type of completion method and helps determine the possibility of sand-production problems. At times diamond coring can aid in operations in areas where very hard and abrasive formations are encountered, because it may be found that coring is more economical than drilling.

Certain petroleum-engineering work is aided greatly by core-analysis data. An understanding of the formation characteristics and composition may lead to the location of (1) oil zones that subsequently might be overlooked, and (2) impermeable zones that may aid greatly in work-over operations to shut off undesirable water or free gas. Core data almost always help the engineer evaluate subsequent work-over possibilities. One of the earliest engineering uses of core-analysis data was for evaluating and planning secondary oil recovery by water flooding. Today, in addition to that same use, it also aids in evaluating gas cycling and pressure maintenance by gas-injection projects. Probably the latest and perhaps one of the most valuable uses of modern core-analysis data for an engineer is to provide basic data for reservoir-analysis studies.

CORRELATION BETWEEN CORING AND ELECTRIC LOGGING

In considering the value of core data, one must remember that the examination of formation cores, either in the field or in the laboratory, provides the only direct information concerning the physical properties of the formation that the drill penetrates and that these core data are the basis of electric and other log interpretations. An examination of formation cuttings and the use of other logging devices may substantiate core-analysis data, but individually those methods are usually subject to variable factors and broad interpretations. When the geologist uses core data for correlation, he is generally certain that they are accurate; and once the reaction of an electric log in a particular formation in a certain area has been established or substantiated by core-data interpretations, the log becomes a very useful tool. Likewise, formation tests are necessary to determine electric-log characteristics in regard to the probable type of fluid that a formation will produce. It has been found that an interpretation of electric logs of certain holes is often very misleading; the logs are very valuable, however, in determining the tops and thicknesses of certain sections when they are used in conjunction with core data, especially when core recovery has been poor.

Since electric logs are influenced sometimes by the type of drilling mud and the mineral content of the section logged, core logs are often the only means of formation interpretation. Sometimes a correlation between an electric log and a core log on producing formations results in finding measurement errors, which may cause subsequent difficulty. In using electric logs for purposes other than correlations, limitations must be recognized, such as failure to register the presence of sands or other zones in a producing horizon and the reverse reaction on producing sands in certain areas.

LIMITATION OF CORING TECHNIQUES AND APPLICATIONS TO GEOLOGIC PROBLEMS

Even though coring is the best tool available for the correlation and interpretation of geologic formations, it too has certain limitations that must be recognized. Perhaps the greatest limitation of coring is that samples of the complete section cored are rarely obtained for examination. The amount of cored section recovered is often as low as 60 percent, and sometimes there is no recovery. When full recovery is not obtained, it is usually difficult to place the recovered section in the correct position in the formation log and to assign physical values to the entire section from those obtained by analysis of the recovered section. Then too, after a core has been recovered, it is not possible to analyze the entire recovered section; thus more limitations are introduced, because the core has to be sampled and tests obtained only on the sampled portions. Work on gas-oil and water-oil contacts from core-analysis data has certain limitations. Usually oil percentages, determined from core analysis, are much lower above the gas-oil contact than below it, but this is not always true, especially when the oil has a rather high gravity. Frequently a recovered core near the water-oil contact appears to contain more oil than those higher in the oil column. Past experience has indicated that cores usually are subjected to considerable flushing by filtrates from drilling muds. When water-base muds are used, oil is generally flushed from the core; therefore oil-saturation values determined from core analyses may be too low. Likewise, when oil-base mud is used, the water-saturation values determined on some cores, especially those near or below a water-oil contact, may be erratic. It has also been found that some oil sections contain argillaceous materials which may have various types of nonproducible bound waters, and these in turn may introduce a considerable error in core-saturation determinations.

Another appreciable limitation of coring results from the fact that it is usually very expensive and causes marked increases in over-all well costs when it must be used. The development of more economical methods to evaluate subsurface formations accurately as well as to find ways to reduce coring costs would be a major contribution to the oil industry.

Reprinted from *Subsurface Geologic Methods*, 1951, p. 619-625.

Chapter 35 DRILLING FLUIDS

T. H. Dunn

The rotary-drilling method requires the use of a circulating fluid forced down the drill pipe and through holes in the bit. After jetting against the bottom of the hole at high velocity, the drilling fluid returns to the surface between the drill pipe and the walls of the hole or between the drill pipe and the walls of the casing. In the surface portion of the mud system, the drill cuttings are removed by screening or gravity settling, and drilling fluid is recirculated.

Drilling fluid performs a number of functions, the primary ones being to remove cuttings from the hole; maintain sufficient hydrostatic pressure to prevent gas, oil, and water from flowing into the well; cool and lubricate the bit; prevent unconsolidated formations from caving into the hole; and suspend sand and cuttings in the hole when circulation is stopped.

In addition to the positive functions, drilling fluid has some negative requirements: (1) it must not damage the producing capabilities of formations; (2) it must not alter or flush cores and cuttings to the extent that estimates cannot be made of the original fluid content; (3) it should not interfere with electric-logging operations nor cause the curves to be altered in a manner that will confuse the interpretation; (4) it must not be corrosive to equipment or injurious and hazardous to persons; and (5) the cost must not be excessive.

Such great strides have been made in the development of drilling fluids in the last 30 years that now they can be designed to meet practically any desired specifications by the use of materials available in nearly all oil fields. Improved drilling fluids, together with great advances in the mechanics of drilling, have enabled penetration of the earth's crust to a depth of 4 miles. The necessity of drilling at increasingly greater depths for oil and gas has been accompanied by progressively greater drilling costs. These mounting costs render it more necessary than ever that commercial oil or gas zones are not overlooked and that reliable geological information be obtained even in dry holes to avoid unnecessary additional drilling. The reliability of information furnished by cuttings, cores, and electric logs is dependent upon the properties of the drilling fluid and drilling conditions.

The various functions and requirements demanded of drilling fluids assume a different order of importance under widely varying drilling conditions; thus, it is difficult to generalize as to the most important functions or characteristics of these fluids. Compromises must always be made to effect some balance between contradictory requirements. It will be to the geologist's advantage to recognize these limitations and to cooperate actively with the drilling engineers in devising a drilling-fluid program that best satisfies all demands.

PROPERTIES AFFECTING PERFORMANCE OF DRILLING FLUIDS

Density

The density of a drilling fluid is important in confining formational fluids to their respective zones. The difference between the pressure exerted by the column of drilling fluid and the pressure of the confined fluid in the formation determines the safety factor in controlling the ingress of fluids into the hole. This property of the fluid is of extreme importance in preventing blowouts in most deep-drilling operations. Density is also important in preventing unconsolidated formations from caving into the hole. In some instances, density must be controlled carefully to prevent the drilling fluid from becoming heavy enough to induce fractures and to escape into the formation. The costly drilling problems of caving and loss of drilling fluid also interfere with the continuous recovery of cuttings needed by the geologist for making logs of the formations being penetrated.

The density of a drilling fluid has a pronounced effect upon the ability of the fluid to recover cuttings from a well. If all drilling-fluid properties and drilling conditions are held constant, the rate of slip of cuttings in the drilling fluid is a direct function of the density of the cuttings minus the density of the drilling fluid. As the density of a drilling fluid approaches 20 pounds per gallon, cutting slip becomes negligble and cutting recovery becomes independent of the yield value and plastic viscosity properties of the drilling fluid. It is usually impractical to increase the density of drilling fluids to improve cutting recovery;

however, when the density must be carried at high values to control formation fluids or caving, maximum use of this property should be utilized to attain satisfactory recovery of cuttings.

The amount and specific gravity of the suspended solids usually determine the density of drilling fluid. Many wells are drilled with densities not over 9 pounds per gallon, whereas in other instances, densities as high as 20 pounds per gallon are needed. Ground barite is commonly used to increase the density of drilling fluids.

Viscosity

Viscosity is important in many of the drilling-fluid functions and characteristics. Viscosity, as applied to drilling fluid, may be regarded basically as meaning the resistance that the drilling fluid offers to flow on being pumped. The removal of cuttings and sloughing shale fragments requires a fluid of certain minimum viscosity for a given upward velocity of mud circulation. Viscosity affects the slip of cuttings; the greater the viscosity the lower will be the slip. Water, rather than more viscous drilling fluids, can be used for carrying cuttings to the surface; however if water is used, it must be circulated at a greater velocity than more viscous media. If the rate of circulation is too low for a drilling fluid of a given viscosity, the cuttings are commonly reground to so small a size that they are useless for geological examination.

Most drilling fluids are plastic fluids rather than true fluids. The most important difference between a true fluid and a plastic fluid in predicting flow characteristics is that a plastic fluid does not have a constant viscosity in the region of streamline flow; i.e., the apparent viscosity decreases steadily as the rate of shear increases. In the quiescent state, a plastic fluid is an elastic solid that will resist permanent deformation by any force less than its initial shearing stress or yield value. In the turbulent-flow region, both plastic fluids and true fluids react the same way. Drilling fluid is usually in turbulent flow in the drill string and in at least part of the annulus immediately above the bit.

The viscosity of a drilling fluid depends upon the amount and character of the suspended solids; the greater the percentage of suspended solids, the greater the viscosity. Plastic clays, particularly bentonite, develop much higher viscosities than do noncolloidal substances such as sand and most clays and shales.

Viscosity of drilling fluid ordinarily is determined in the field by means of a Marsh funnel, which is a cone-shaped funnel that is filled with the fluid to be tested. The time necessary to discharge a measured volume of the fluid is an indication of its relative viscosity. Rotational viscometers, the Stormer and others, are used both in the laboratory and in the field. In these viscosimeters a spindle is rotated in a test cup, and the force necessary to drive the spindle at selected rates of rotation is measured and converted into centipoises by means of suitable calibrations.

Plastic-Flow Properties

The fact that most drilling fluids are plastic fluids instead of true fluids has led to much research in an attempt to analyze correctly the complex flow behavior of plastic flow and to develop appropriate rheological measurements. It is now generally recognized that Bingham's law of plastic flow can be utilized in describing the hydrodynamic behavior of drilling fluids in the nonturbulent flow range; namely, the flow behavior is characterized by two constants, plastic viscosity and yield value. Sometimes the term rigidity is used for plastic viscosity, or the term mobility for its reciprocal.

The plastic viscosity of a substance obeying Bingham's equation is defined as the constant ratio of a given change in the shearing stress to the corresponding change in the rate of shear when the body is undergoing permanent deformation or flow. This same definition applies also to the viscosity of a true or Newtonian fluid. The yield value of a plastic substance may be defined as the difference between the shearing stress and the product of the plastic viscosity and rate of shear.

Rotational-type viscometers capable of being operated over a wide range of shear rates are commonly used to measure the two plastic-flow constants. Methods have been developed of estimating from the flow-constant measurements the effects of changes of drilling-fluid properties on various drilling items; for example, circulating rates and pressures, pump-horsepower requirements, and cuttings-carrying capacity. It has been shown that the cuttings-carrying capacity of a plastic drilling fluid of a given density is dependent upon the size and shape of the cuttings, the plastic-flow constants, and the flow state of the drilling fluid, i.e., laminar or turbulent flow. Where the drilling fluid is in laminar flow, an increase in either plastic viscosity or yield value results in increased ability to lift cuttings, whereas in turbulent flow an increase in the plastic viscosity, will increase the ability of the fluid to lift cuttings.

Selection of optimum flow constants in a particular drilling situation is possibly one of the most important means of improving the recovery of cuttings. Despite considerable study of this subject to date, it has not been possible to develop precise generalized recommendations to cover all drilling conditions—for instance, channeling of mud past enlarged spots in the hole and the fall of cuttings through a thixotropic mud in which flow has been suspended.

In practice, a drilling fluid having a high yield value, a low plastic viscosity, and some initial gel strength will usually serve to carry cuttings from the bit to the surface most effectively. This drilling fluid will tend to be in laminar flow in the annulus between the drill pipe and wall of the hole and in plug or laminar flow in hole enlargements.

Gel Strength

The gel strengths of drilling fluids are of particular importance. Gel strength refers to the minimum shearing stress that will produce permanent deformation of the plastic drilling fluid after a given period of quiescence. Gel strength increases with increased time of quiescence of the drilling fluid until a maximum is reached. It is principally the gel strength of the drilling fluid that holds cuttings and weighting material in suspension when circulation is stopped.

In general, gel strength should be low enough to allow sand and shale cuttings to settle out in the ditches and mud pits, permit entrained gas to escape at the surface, minimize swabbing when pipe is pulled from the hole, and permit starting of circulation without the use of high pump pressure. The gel strength usually should be high enough to retard the settling of weighting material in the pits and to prevent the formation of a settled fill at the bottom of the hole when circulation of drilling fluid is suspended. Except in special cases, 10-minute Stormer gel strengths of 10 to 20 grams are suitable. The subsequent increase of gel strength with increased time of quiescence should be as small as practicable because development of high gel strength promotes the formation of stagnant gelled zones of drilling fluid in hole enlargements. Cuttings and cavings tend to collect in these zones, and later unload into the flowing drilling-fluid stream. When this condition exists, cuttings identification from formations then being penetrated is difficult. This condition also can cause severe drilling difficulties.

A Stormer viscometer, which is the rotational type mentioned previously, commonly is used to determine gel strengths. The fluid to be tested is stirred thoroughly and poured into the test cup. The initial gel strength is the minimum weight in grams required to cause rotation of the spindle ¼ revolution. The 10-minute gel strength is the minimum weight in grams required to cause rotation of the spindle after the thoroughly agitated fluid has remained quiescent for 10 minutes.

Filter Loss

The filter loss and wall-building properties of drilling fluids are recognized as being of major importance in the proper drilling of wells. As the drilling fluid is circulated over the walls of the hole, there is a tendency for the liquid phase of the mud to be filtered into the surrounding formation and to leave the solid matter to be deposited on the face of the formation in the form of a coating or filter cake. The formation of a filter cake is essentially a bridging of the exposed pore openings in the wall of the well. Relatively coarse mud particles may be required to start the bridging of the pores. If the filter loss is to be reduced effectively, the space between the relatively large particles must be bridged successively with smaller particles until eventually the smallest particles approach the size of molecules. The colloidal properties of a drilling fluid largely determine its ability to form thin impervious filter cakes and have low filter loss.

High filter loss may often result in filter cakes becoming thick enough to cause tight places in the hole and even sticking of drill pipe. High filter loss with water-base muds often harms the productivity of wells by excessive invasion of the formation, and sometimes causes an excessive dispersement of cuttings and serious sloughing and caving of shale. In addition to minimizing drilling problems, low filter loss aids in the recovery of cuttings and cores more useful for geological examination and reduces the amount of cavings that interfere with the evaluation of cutting samples. Low filter loss aids also in obtaining satisfactory electric logs and reliable drill-stem tests.

The permissible filter loss of a drilling fluid varies over a wide range and depends upon the particular area and drilling situation. For example, clear water is satisfactory for drilling to considerable depth in some areas, whereas drilling fluids of low filter loss are ordinarily required for drilling deep wells, particularly those in which incompetent shales must be penetrated. In general, specification of the permissible filter loss must be based upon past drilling experience in the immediate area, including such overall factors as total drilling cost, major drilling difficulties, productivity indices, and drilling-fluid costs.

Filter loss is commonly determined in a small filter-press cell approximately 3 inches in diameter. The fluid is forced against a screen-supported filter paper on which the filter cake is formed at 100 pounds per square inch. The thickness of the filter cake and the amount of filtrate passing through the filter paper are measured after 30 minutes.

pH Values

The pH of drilling fluids, i.e., the degree of alkalinity or acidity, is important in the control of several types of drilling fluids and in minimizing dispersion of cuttings. The pH is preferably maintained as low as practicable; normally a pH of 9 to 10 is satisfactory for most treated native muds. The pH is commonly from 10 to 11 for muds treated heavily with caustic soda and organic thinners and above 12 for lime-treated and high-pH starch drilling fluids.

Protection of Pay Zones

Possibly the most critical property of a drilling fluid is that of protecting the pay zone without impairing the productivity of the zone. The discovery of valuable production from meticulous geologic and other exploration surveys should not be prevented by plugging of the pay formation of the wildcat well by drilling fluid. Formations differ widely in their tolerance to damage by drilling fluids. Fortunately, the fact that many productive formations are not harmed appreciably by drilling fluids undoubtedly accounts for the large amount of oil and gas production obtained in the past.

It has been recognized during the past decade that a great amount of oil and gas production may have been overlooked or condemned in the past because of the injury to the pay zones by the drilling fluid used to pentrate them. Formations that are damaged easily by drilling fluids are usually termed sensitive formations. These formations usually have relatively low permeabilities and contain much shale, clay, and silt.

Permeability impairment may result from one or more of several causes: (1) if a drilling fluid is used that permits much water to filter into the pay formation, clays present in the formation may swell and cause reduced permeability; (2) water filtrates may weaken adhesion bonds between small particles in the interstices within the formation and permit these particles to migrate and plug flow channels at constrictive points; (3) water filtrates may collect as globules in the interstices to plug flow channels at constrictive points because of interfacial effects; (4) water filtrates may contain soluble salts that will react with soluble salts in the interstitial water to precipitate solids or form gels that will plug flow channels at constrictive points and injure the permeability of the formation; and (5) solids from the drilling fluid may penetrate the formation and cause some permanent reduction of permeability to oil.

Drilling fluids that filter oil into producing formations will overcome many of the difficulties caused by water filtrates but sometimes may not completely prevent damage to the producing formation. Oil filtrates will not permit the swelling of interstitial clays, but they may weaken adhesion bonds between small particles in the interstices within the formation and permit them to migrate and plug flow channels at constrictive points. Oil filtrates will eliminate the possibility of water blocking oil-wet formations, but constituents of some oil filtrates may react with soluble materials in the formation oil to form precipitates that reduce permeability. Solid particles from oil-base muds, especially when weighted, may penetrate the formation during the initial stages of filtration before a filter cake is deposited, plug the flow channels in the producing formation at constrictive points, and reduce permeability.

No single drilling fluid will protect all pay formations from every possible cause of sensitiveness. Several preventive measures, however, can be used until the specific causes are discovered and the correct drilling fluid is designed. Because solid particles from the drilling fluid must penetrate the pay formation before they can cause plugging, such penetration by these solid particles can be kept at a minimum by maintaining in the drilling fluid a uniform distribution of particle sizes capable of plugging the extreme range of expected pore sizes in the pay formations. The differential pressure between the circulating drilling fluid and the fluid in the pay formations should be maintained as low as possible to minimize the tendency of the drilling fluid to spurt into the pay formation before a protective filter cake has formed. Likewise, filtrates from drilling fluids cannot harm formations they are not permitted to enter. Filtrate penetration can be minimized by maintaining differential pressures as low as possible and by using drilling fluids having low filter losses.

Certain water-base drilling fluids termed inhibited muds have been developed for some formations that are specifically sensitive to water filtrates because of the swelling of interstitial clays. When the formations are sensitive to filtrates from water-base drilling fluids for several reasons other than swelling of clay, the use of oil-base drilling fluid or oil-base emulsions that filter only oil may be necessary.

Air or gas is advantageous especially as a drilling fluid in drilling sensitive formations since gaseous drilling fluids cause minimum damage to such formations.

TYPES OF DRILLING FLUIDS

The drilling fluids in use today fall into three general classes: water-base, oil-base, and gas-base (fig. 35-1). Drilling fluids intermediate between water- or oil-base and gas-base are of the gas-in-water or gas-in-oil type, which are generally known as gas-cut drilling fluids; or they are of the water- or oil-in-gas type, about which little has been published. Drilling fluids intermediate between water-base and oil-base are of the water-in-oil and oil-in-water types which generally are known as oil-base emulsions and water-base emulsions, respectively.

Water-base drilling fluids comprise the major portion of all drilling fluids in use today. Treated native muds predominate in this class of drilling fluids.

Oil-base drilling fluids consist of oil in which are dispersed materials for raising viscosity and gel strength and lowering filter loss.

Gas-base drilling fluids consist of a gas, such as air and methane, in which are suspended the material being drilled and eroded or sloughing from exposed formations.

KINDS OF DRILLING FLUIDS

Numerous types of drilling fluids are available within the major classifications of water-base and oil-base mud. The diversity of drilling-mud systems results from the varied requirements of drilling fluid—requirements that depend upon such factors as depth of well, type of formation, and local structural conditions. For example, drilling through limestone entails the problem of loss of fluid in cavernous voids but no sloughing or caving of the hole, whereas drilling through some shale types entails problems of sloughing and caving but no problem of loss of fluid. In these two instances, the requirements

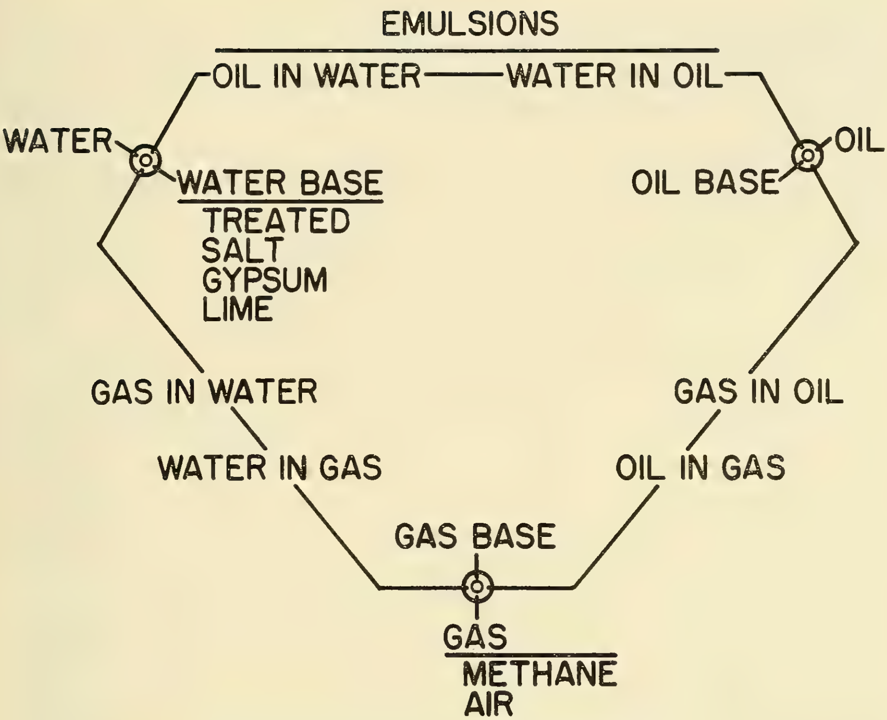

FIGURE 35-1. Types of rotary drilling fluids.

for the proper drilling fluid vary widely. Fresh-water-clay drilling fluid meets requirements in many drilling conditions but is unsuitable in others were salt contamination is excessive.

The following summary lists some of the more important types and names of available drilling fluids.

Water-Base

Water

Water, either fresh or saline, is used in some areas where only firm, relatively tight formations are exposed. The drilling water is clarified in a special settling pit or by chemical coagulants. Oil emulsifiers, special clay flocculants, and surface-active compounds are sometimes used with the water to retard corrosion and wear on bits, to speed drilling rates, and to aid in recovery of cuttings suitable for geological purposes.

Water may also be used to spud in wells in some locations, and then it may be used to accumulate fine solids and become natural drilling mud.

Fresh-Water-Clay Muds

Natural muds are formed from the drilled formations. With continued drilling, continual dilution with water often is required to maintain the mud so that it is easy to pump.

Phosphate muds are natural muds treated with one of more of the complex phosphates to thin the mud and aid in reduction of filter loss. Complex phosphates commonly used are sodium hexametaphosphate, sodium acid pyrophosphate, sodium tripolyphosphate, sodium tetraphosphate, and tetrasodium pyrophosphate. Phosphate muds are suitable where there is little contamination with anhydrite or where the salt content is less than 1 percent.

High-pH red mud is usually natural mud treated with relatively large concentrations of caustic soda and one or more of the organic-type thinners such as quebracho, lignite, hemlock extract, mangrove bark, and tara bean extract. This mud is chosen ordinarily because of its somewhat greater tolerance to contamination with salt. Starch is frequently used to reduce filter loss.

Lime-treated mud is similar to high-pH red mud in composition except for addition of slaked lime to convert the mud to calcium clay base. Lime mud is used primarily in deep drilling where mud-making shales are exposed or where considerable salt water contamination occurs. Calcium lignosulfonate sometimes is substituted for most of the quebracho or other organic thinners. Lime mud can resist salt contamination of several percent as well as contamination with gypsum, anhydrite, and cement to an extent exceeding the tolerance of muds not treated by lime. Lime muds generally have low viscosities and exceptionally low gels, and at temperatures lower than 250F, lime muds have the ability to remain quiescent for long periods without excessive gelling. These properties permit ready degassing, high circulating rates, and minimum shale sloughing. Lime-treated mud tends to solidify at temperatures above 250F. Centrifugal separators or hydraulic cyclones may be used to reduce the clay solids content of the mud and thereby overcome the solidification problem. Another approach to this problem has been the preparation of the lime-treated mud with selected optimum proportions of caustic soda and a minimum amount of lime and an organic thinner. More recently, a barium-base mud has been developed to combat the solidification problem. In some instances high-pH lime-treated muds have interfered with electric logging because of their relatively low resistivities.

Gypsum muds consist of native fresh-water muds to which are added controlled amounts of Plaster of Paris to convert the clay solids to calcium-base clays and starch to control filter loss. The muds are designed specifically for drilling thick sections of anhydrite that may be followed by sections of salt. These muds usually have desirable electric-logging properties.

Inhibited and surfactant drilling fluids are relatively new water-base drilling fluids used in drilling formations in which other water-base drilling fluids, even with controlled low filter loss, do not adequately retard the sloughing and caving of shale and clay formations nor the excessive dispersement of bit cuttings into the mud. These special fluids contain combinations of salt, gypsum, calcium acetate, calcium chloride, lime, and potassium chloride designed to eliminate the foregoing problems. Surfactant drilling fluids are usually used as water-base emulsions. The cuttings and wall cavings introduced into these drilling fluids are rendered preferentially oil-wet by the surfactant and thereby are coated with oil from the emulsion. This oil coating adheres tightly to the cuttings because of the surfactant, and the coating usually is very effective in retarding the swelling and dispersement of the cuttings until they are removed by the screens. Both inhibited and surfactant drilling fluids, either with or without filter loss control additives, usually recover more of the cuttings than do ordinary water-base clay drilling fluids.

Salt-Water Muds

These muds usually result from drilling salt sections or from encountering salt-water flows. The mud usually is undersaturated with salt; however, saturated salt muds sometimes are used for avoiding hole enlargements when salt beds or salt-dome overhangs are being drilled. Sea water sometimes is used in drilling fluids, usually in lime-treated mud systems, for drilling shale. Organic-type additives such as pregelatinized starch, sodium carboxymethyl cellulose, synthetic polymers, or natural gums are used to control fluid loss.

Salt-water muds containing from 20 to 30 percent salt have very low resistivity, which makes interpretation of electric logs difficult. Often a separate batch of fresh-water-clay mud must be spotted in the hole for obtaining suitable electric logs.

Emulsion Muds

These fluids fall into two classes: water-base emulsions and oil-base emulsions. Water-base emulsions are those in which the oil is dispersed as small droplets through the water, whereas oil-base emulsions are those in which the water is dispersed throughout the oil.

Water-base emulsion muds are compounded from virtually all of the water-base muds by addition of approximately 3 to 30 percent of various oils. Emulsifiers also are used frequently to stabilize the emulsions. Emulsion muds have become quite popular and are used to increase drilling rates, reduce torque on drill pipe and give greater bit life and holes more nearly to gage. Sometimes misleading shows of oil may be found in cores cut with emulsion mud, but this problem can be avoided largely by having the emulsion mud properly emulsified and stabilized prior to starting coring operations, by not subsequently adding additional oil, and by using refined oils such as diesel fuel in preparing the mud. Crude oil should be avoided in preparing emulsion mud where the determination of productive zones depends upon correct interpretation of well cuttings. The use of refined oil is not as serious since fluorescence will differentiate between most crudes and refined oil.

Oil-base emulsion fluids have most of the properties of oil-base drilling fluid since oil is the continuous phase and predominates in the filtrate. One of these emulsion fluids is prepared by addition of a dry concentrate to the proper ratio of oil and water (Lummus, 1954). In field practice a ratio of 40 to 60 percent water and the remainder oil is used normally. A nonfluorescing oil and an emulsifier in this mud minimize difficulties in geological interpretations. Oil-base emulsion fluids are used primarily for drilling in or recompleting wells in formations whose productivity may be harmed by water-base-type drilling fluids. Special interpretations of electric logs usually are required when these drilling fluids are used.

Oil Base

Commercial oil-base fluids are various base oils in which materials for raising viscosity, gel strength, and lowering filter loss are dispersed. Dry concentrations have been developed for conveniently preparing oil-base fluid from a wide variety of oils. The main use for oil-base fluids has been for drilling in formations that may be harmed by water-base fluids, for coring operations to recover native state cores for connate water determinations, and for reservoir studies. Special interpretation of electric logs is required due to the high resistance of the oil-base fluids. An advance in electric logging in oil-base fluids has resulted from the development of the induction log.

Crude oil alone is used frequently as a drilling fluid for completing wells in tight sands and for workover jobs.

Gas Base

Air or natural gas is being used as drilling fluid to an increasing extent in some areas. Use is limited to areas where weighted fluids are not required and where formations contain little or no water. The main advantages of gas drilling are high drilling rates and minimum damage to producing formations. Excessive moisture causes balling of the bit cuttings around the drill stem and frequent sticking of the tools; this inability to cope with water-bearing strata is a severe limitation.

Suitable cores and cuttings usually are obtained in gas drilling both for geological and reservoir study. Electric logging is complicated in this method of drilling.

Combinations of air- and water-base muds, commonly referred to as aerated muds, have been utilized as drilling fluids. The water-base muds used in aerated mud drilling can range from clear water to high pH viscous muds. Aerated muds offer some of the advantages of air or gas in increased drilling rates and, in addition, have the advantage of being applicable in drilling water zones and in being easily and rapidly convertible to heavier muds when necessary. Corrosion is often a severe problem in the use of aerated muds.

DRILLING CONDITIONS AFFECTING DRILLING FLUIDS

Lost Circulation

A particularly important problem relating to drilling and drilling fluids is the loss of hole fluid into formational voids. This loss of drilling fluid is termed lost circulation or lost returns and differs from filter loss in that the complete drilling fluid enters the formation. Lost circulation occurs in two general types of formations: (1) formations naturally capable of taking drilling fluid because of intrinsic fractures, channels, vugs, or intergranular type porosity, and (2) incompetent formations in which fractures are induced by hydrostatic pressure of the drilling-fluid column. Despite precautionary measures to avoid imposing unnecessarily high pressures on the penetrated formations, lost circulation still occurs in many instances, and it is necessary then to add materials of relatively large particle size to seal the voids in the wall of the hole. Among the materials most commonly used to stop loss of returns are fibrous materials (leather fibers, sugar-cane fibers, asbestos fibers), granular materials (ground walnut shells, expanded perlite), and flaked materials (cellophane flakes, mica flakes).

Drilling-String Mechanics

Poor drilling-string mechanics can result in increased drilling fluid maintenance costs and in decreased and unreliable cuttings recovery. When high weight is maintained on the bits by imposing weight beyond the buckling strength of the drilling string, excessive grinding action results between the drilling string in compression and the walls of the hole. This action not only tends to grind up cuttings and cavings to form suspended solids in the drilling mud but also enlarges the bore hole, thus reducing the efficiency of the drilling mud to lift cuttings and cavings to the surface. This condition can be remedied by using a sufficient number of adequately sized drill collars and keeping the rotary speed below the critical point above which instability results in the drilling string.

Annular Velocity of Drilling Fluid

Maintaining the velocity of the drilling fluid in the annulus as high as possible will improve materially the removal of cuttings and cavings from the bore hole. All cuttings and cavings will be subjected to a certain amount of grinding action even if the optimum drilling-string mechanics are in use. The more rapidly cuttings and cavings are removed from the bore hole, the less they will be broken down by the grinding action of the drilling string. As long as the flow properties of the drilling fluid remain unchanged, increasing the annular velocity will remove the cuttings and cavings from the hole more rapidly. This rapid removal will assure maximum cutting recovery and minimum drilling-fluid maintenance costs.

Wall Cutting

Wall cuts will occur frequently in wells in removing drilling pipe and bits from the hole. If these wall cuts wear deeper than the radius of the drill pipe, they will be wiped out on trips (fig. 35-2). This wiping out will dump large quantities of shale into the drilling mud and thereby confuse interpretation of cutting samples. Wall cuts can be minimized by paying strict attention to drill-

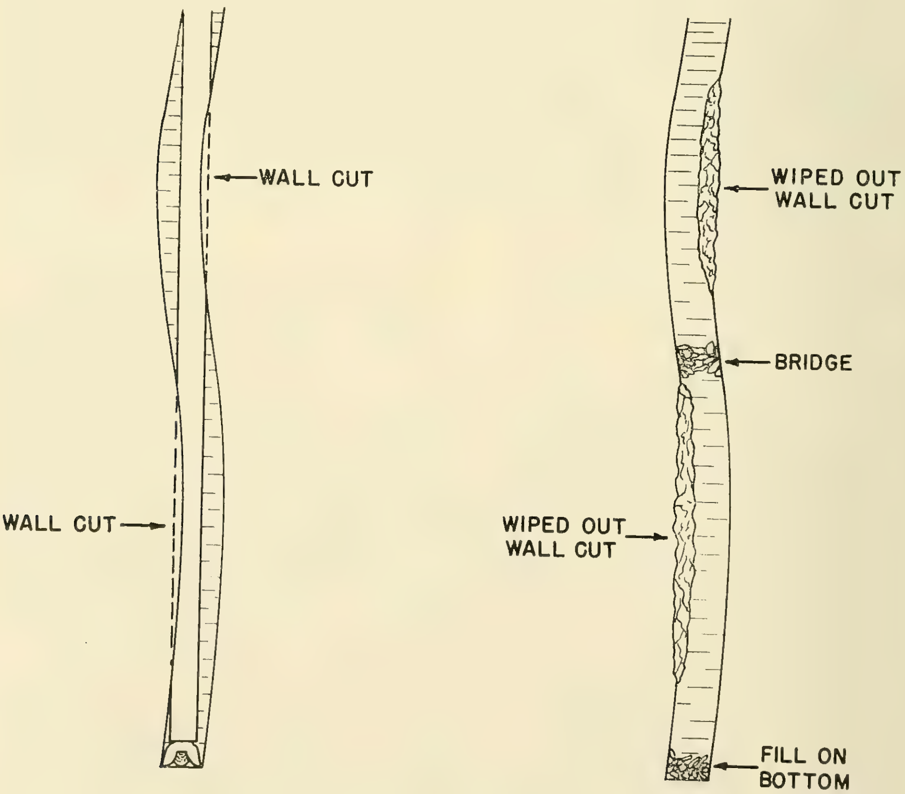

FIGURE 35-2. Wall cuts in a drill hole.

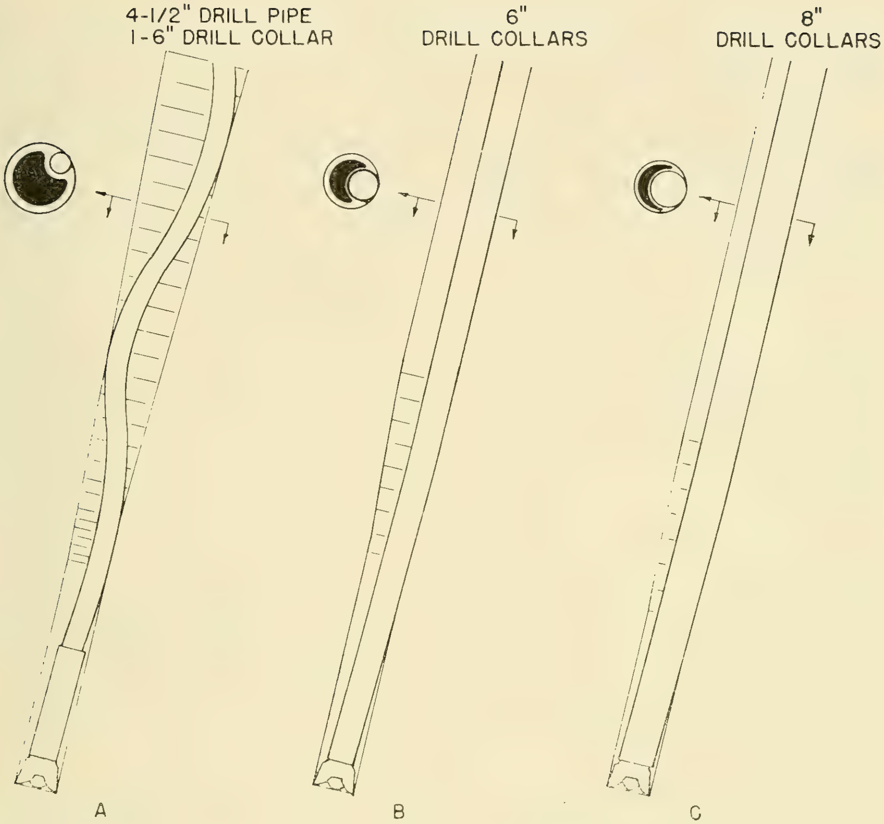

FIGURE 35-3. Relation of drill string and hole.

pipe mechanics. Proper drill-pipe mechanics will avoid abrupt changes in hole direction. If points are discovered where wall cuts are developing, reamers should be occasionally spotted in the drilling string to prevent their being cut so narrow that they will be wiped out on trips. Wiped-out wall cuts usually produce hole enlargements that reduce the effciency of the drilling fluid to carry cuttings past these points.

Vertical Hole

Drilling an absolutely vertical hole is practically impossible and would be dynamically unstable. Most holes will be inclined a degree or more from the vertical and usually will spiral in a clockwise direction towards the bottom. When the drilling-string mechanics are in proper adjustment (fig. 35-3) the drilling string will touch the lower side of the wall a few feet above the bit and lay on this side for some distance up the hole as long as the drilling string is in compression. The force with which the drilling string bears against the wall of the hole is directly proportional to the angle the hole is inclined to the vertical as well as to the effective weight per foot of the drilling string in compression in the drilling fluid. The greater the bearing force of the drilling string against the walls of the hole, the more the cuttings are pulverized to complicate their proper identification. Drilling a hole as vertical as possible is important in avoiding drilling problems and assures the recovery of large-size cuttings for logging purposes.

SURFACE EQUIPMENT FOR HANDLING DRILLING FLUIDS

Screens

Screening equipment is used to assure positive removal of cuttings from drilling fluids. This removal reduces the increase in viscosity and gel strength of the drilling fluid resulting from dispersing cuttings into the mud when they are recirculated. Proper drilling-fluid screening equipment also is essential to secure for geological examination cuttings that are free from recycled material. Screens of the vibrating type commonly called shale shakers are most satisfactory because a finer mesh wire cloth can be used on them and thickey drilling fluids can be screened. Screens of the rotary type necessitate larger mesh wire cloth and function properly only on less viscous drilling fluids.

Desanders, Centrifuges, and Hydraulic Cyclones (liquid type)

Sand is undesirable in drilling fluids because of its abrasive properties. Excessive sand and other fine material also interferes with cutting analysis. Desanders, centrifuges and hydraulic cyclones can be used when screens prove inadequate for removing sufficient sand and other finely divided material from drilling fluids. Cyclones and centrifuges are being used to an increasing extent to recover barite from drilling fluids and to control excessive viscosity and gelation properties by removal of some of the clay fraction from clay-base drilling fluids. Significant savings in drilling costs are achieved in many areas through use of centrifuges and hydraulic cyclones.

Degassers

Drilling fluids of high density often become gas-cut; that is, all the gas absorbed in drilling is not released at the surface, and as drilling progresses the fluid may become so lightened that it is dangerous. Recycled gas in the drilling fluid may also affect or complicate the detection of shows from pay formations as determined by mud logging. Various types of degassing equipment will remove gas from the drilling fluid and thereby eliminate the interference of recycled gas.

Circulating Pits

Properly designed and maintained circulating pits (fig. 35-4) can minimize the need of screens, desanders, centifuges, hydraulic cyclones, and degassers for obtaining satisfactory cutting- and mud-analysis logs. Pits can be designed that will permit settling of all solid material larger than 200 mesh from the drilling fluid as well as permit the escape of entrained air and gas. To accomplish the most efficient functioning of these pits, one should take every precaution to prevent channel flow and to provide sheet or bank-to-bank flow, with numerous falls through the pits. Bank-to-bank flow keeps the drilling fluids in the pits in continuous progressive movement and facilitates the droppings of cuttings, sand, and silt, and facilitates the escape to the surface of the drilling fluid the entrained air, gas, and oil. Sheet or bank-to-bank flow with numerous falls is easily accomplished by providing removable tiered partitions at the proper ends of the pits as shown in Figure 35-4.

Refuse-Reclamation-Reserve Pit

Occasionally drilling fluids are circulated through a properly designed refuse-reclamation-reserve pit, commonly called a reserve pit, to effect maximum removal of cuttings, sand, silt, entrained gas, air, and oil from a drilling fluid.

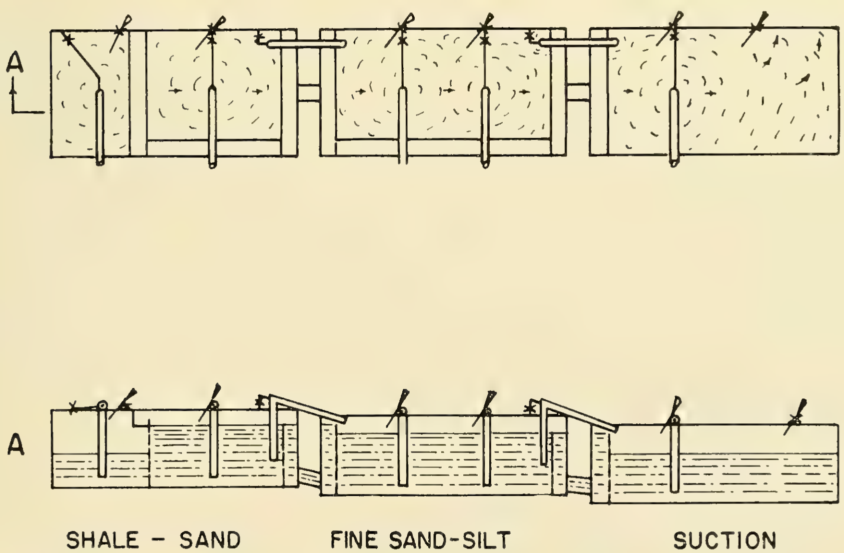

FIGURE 35-4. Circulating pits for rotary drilling fluids.

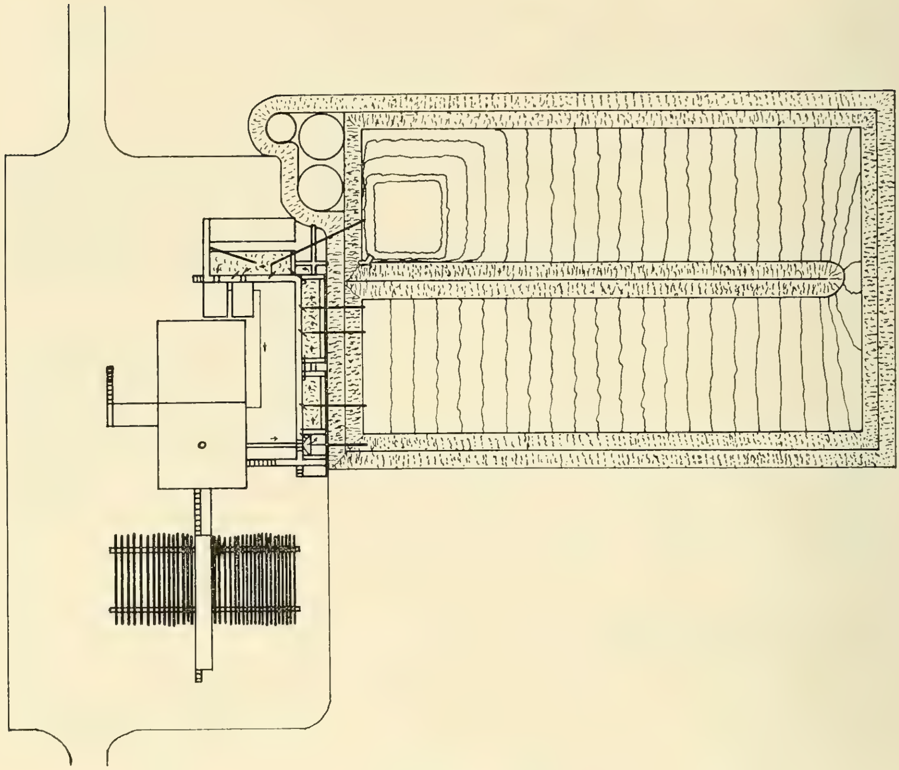

FIGURE 35-5. Ideal drilling fluid equipment layout for a rig.

The design, as shown in Figure 35-5, provides for a partition down the middle, open at one end, and grading the bottom to provide gentle drainage (1/8 to 1/4 inch per foot) from the extreme end of one partitioned side down to the other end, through the opening in the partition, and down to a sump at the other end of the second partition. The drilling fluid containing cuttings, caving, sand, silt, entrained gas, air, and oil flows in at the high end of the first partition where it slowly drains to the sump in the second partition, leaving all debris on the floor of the pit. The entrained gas and air escape to the atmosphere, and the entrained oil breaks out to float down on the drilling fluid and be trapped on the surface of the drilling fluid in the sump. The clean drilling fluid returned to the well assures more satisfactory cutting- and mud-analysis logs.

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Chapter 36 DRILLING WITH GAS AND AIR

M. M. Brantly

As early as 1938, gas was used as a circulating medium in the Texas Panhandle in an effort to speed up the cleaning out of gas wells after shooting with glycerin. The rotary equipment at that time did not efficiently clean the hole of the larger fragments that remained after shooting. By the use of gas, which was readily available in the field, it was possible to obtain a sufficiently high ascending velocity in the annulus to bring out many of the fragments. To what extent this method was used or perfected is not known, but it was probably used only a short time and in relatively few instances. From that time until the late 1940's, very little if any attention was given to the use of gas or air in drilling or completion operations.

The next records of the application of air or gas show that it was used in an attempt to lighten the mud column being circulated in a hole, thereby decreasing the hydrostatic pressure on weak or porous formations which would have otherwise become thief zones. This is still the primary reason for using air or gas in drilling programs. More recently other reasons have developed.

GENERAL PRINCIPLES

In so-called conventional drilling, mud or water is circulated down the drill pipe and up the annulus in order to cool the bit and carry the cuttings to the surface. Basically air and gas function in the same manner. Air is compressed on the surface and pumped down the drill pipe. After leaving the bit, it moves from the restricted drill pipe and drill-collar bore into the annulus. The air travels at high speeds through the openings in the bit and is directed against the bottom of the hole. This action has two immediate benefits: it greatly assists in loosening and lifting the bit cuttings, and it cools the bearings and teeth of the bit. Although the cuttings have a density considerably greater than that of the air, the high velocity of the air carries them up the annulus. As a formation chip moves upwards, the constant contact with the drill pipe, the walls of the borehole, and other chips reduces the size of the chips and makes it easier for the air to carry them to the surface. As the cutting-laden air reaches the surface, it is diverted away from the rig, preferably downwind, and exhausted to the atmosphere.

Besides the chipping action of the bit teeth and the blasting effect of the air, one other condition assists in removing cuttings. The formation being penetrated has been, through an extended period of time, subjected to the weight of the formations lying above. In normal drilling with mud, this formation weight is partially replaced by the head of drilling fluid in the hole. When air is substituted for mud, most of this weight is removed, and the penetrated formation is relieved of nearly all of the downward compression. The removal of this stress is probably responsible for partial breakage of the formation.

DRILLING METHODS

Air drilling involves no major change-over from conventional rotary drilling. Air compressors simply replace mud pumps, and air is substituted for circulating mud. Normally a rotating stripper head is added on the top of the blowout preventer. Minor modifications are made to suit the particular situation or the desires of the company.

The basic principles of rotary drilling do not change just because air has been substituted for mud. The drilling bit is cleaned by circulation. It has been found that drilling with air requires considerably less weight on the bit and that the bit may be rotated at a much slower speed. The combination of weight and rotating speed most suitable for penetrating a particular formation is determined on the basis that the rotating hours obtained from a bit vary inversely with the weight and speed used. In general, it has been found that a good starting point is about one half the weight used with mud and from one half to three quarters of the rotary speed used with mud. No rule of thumb can be followed to determine what combination is best or what rate of penetration should be attempted. It must be realized, however, that the greater the bit life, the greater the percentage of productivity time obtained from the equipment.

Another factor to bear in mind, particularly in the drilling of softer formations, is that the drilling rate should not be faster than the rate at which the hole can be cleaned with the available air volume. The bit can sometimes drill 2 or 3 feet per minute, but generally at this rate the hole cannot be cleaned properly. The time gained in rapid drilling is lost in cleaning the hole before a connection can be made or before a trip. If the weight and rotating speed are reduced to the point where hole cleaning keeps up with pentration, then the bit life is extended to maximum.

In rigging up for air or gas drilling, it should be remembered that there is no weight in the annulus to counteract possible high-pressure zones. For this reason, it is advisable to maintain mud in the pits as a safety precaution.

Another very important factor is the abrasive dust that returns to the surface. If the moving parts of the rig are not protected properly, they will be subject to severe wear. The crucial point of danger is the rotary table, where the ascending air must be deflected into the flow line and carried away. Even a small leak in this area will result in rapid accumulation of dust in the table bearings. Normally some type of rotating stripper head is placed above the flow line so that the packing of the head forms a seal around the kelly to prevent the dust from entering the rotary table or from coming through to the rig floor. The flow line should be of sufficient length and oriented in a direction that will prevent the dust from being blown over the rig. If conditions permit, it is advisable to set two flow lines in opposite directions so that a downwind line is always available.

It has been agreed generally that, for proper hole cleaning, the ascending air velocity should be approximately 3000 feet per minute. To determine the volume of air required, the hole size and the drill-pipe size must be considered. As Table 36-I shows, maintaining the proper annular velocity in the larger hole sizes is impractical. In general, the velocity in large holes is allowed to drop below that which is considered desirable because the cost of the additional equipment to maintain 3000 feet per minute would be prohibitive. In this instance, gas often has a decided advantage over air in that greater volumes normally are available. Regardless of the conditions, it is advisable to have an excess volume of air available to accommodate unusual situations that may arise.

Air-pressure requirements will vary with drilling conditions, but in general they are quite low. For example, drilling a 7⅞-inch hole with 4-inch drill pipe and 6-inch drill collars at 5000 to 6000 feet, a pressure of 100 pounds per square inch is ample as long as the hole is dry. The pressure requirements will increase with depth and will be further increased if damp or wet formations are encountered. The majority of the compressor equipment now used is capable of sustained operations at pressures up to 350 pounds per square inch, which are adequate for any drilling problems encountered thus far. When the formation becomes wet, it is advisable to have an additional booster compressor capable, not only of increasing the air pressure up to 1000 or 1500 pounds per

TABLE 36-I

Approximate air volume to maintain 3000 feet per minute annular velocity. Corrected for line and pressure losses.

Hole Size	Drill Pipe Size	CFM
7⅞″	3½″	1050
	4½″	950
	5½″	675
8¾″	3½″	1770
	4½″	1600
	5½″	1370
9⅞″	3½″	2200
	4½″	2050
	5½″	1820
11″	3½″	2720
	4½″	2550
	5½″	2320
12¼″	3½″	3340
	4½″	3170
	5½″	2940
13¾″	3½″	4180
	4½″	4010
	5½″	3800

square inch, but of delivering a substantial volume. Such equipment is usually too expensive to be maintained on the job permanently.

Since air conforms to Boyle's law, the temperature factor can become a major problem, particularly at high pressures in a damp or wet hole; therefore almost all compressors are equipped with an inner and after cooler. An additional cooling phase is sometimes put in the line between the compressors and the standpipe. In general, oil-field rubber goods, such as rotary hoses and packing, are designed to operate at temperatures below 250F. If the air temperature exceeds this value for any extended period, the life of the rubber is reduced materially. Sometimes one or two of the cooling stages are by-passed, but careful consideration should be given to all factors concerned before this is done. Because cool air can hold less moisture than warm air, the cooling stages also serve as dehumidifiers. On the other hand, where moisture is present in the hole, warm air will more effectively remove the moisture from the hole and assist in drying it. The moisture content of the air being compressed must be considered in deciding whether or not to by-pass one of more of the cooling stages.

The severity of the dust-disposal problem varies from location to location and depends on whether the well is being drilled near habitations. In some areas, no attempt is made to control the air, except to prevent its blowing back onto the rig. The methods of dust control most commonly used consist of either separating the air from the dust in a cyclone-type separator or taking the dust out of the air with water sprays. There are almost as many variations of these two methods as there are air-drilling rigs. In many instances, improvisations or refinements are made on the job. To maintain good public relations and to avoid damage suits, some method or combination of methods must be developed to fit the circumstances.

Fishing operations in air-drilled holes are more simple than those in a fluid-drilled hole because air-drilled holes can easily be cleaned of all cuttings, thus reducing the possibility of the "fish" being stuck or of the cuttings preventing the fishing tool from reaching its target.

Diamond coring is quite satisfactory with air if the proper type of bit is used and if there is no core contamination. Fluid loss from the core because of decrease in pressure is no more serious than contamination by water or mud infiltration into a conventional core. The increase in penetration rate with a diamond-core head is equivalent to the increase with a drilling bit.

AERATED MUD OR WATER Drilling with mud and drilling with air have been discussed. Between these two are in infinite number of combinations of fluid and air. Aerated fluid is used to combat one or more of the disadvantages of air drilling.

If water is present in the hole and creates a condition that causes sticking of the drill pipe, water then may be added to the system to thin the slurry in the hole so that it may be blown out. In general, the lowest ratio of fluid to air that will successfully accomplish the purpose is the most desirable.

When aerated fluid is used, it is important that the fluid be saturated with lime to prevent rapid corrosion of the drill pipe. If an appreciable quantity of water enters the hole, it becomes difficult to maintain the lime saturation, and corrosion may still result.

There are no hard and fast rules as to the most appropriate ratio of fluid to air for any particular situation; therefore, this ratio must be determined in the field at the time of the operation. The ratio of fluid to air should be governed by the hole conditions. If low-pressure zones are present, the water should be decreased. Conversely, if water flows are present, the ratio of water to air should be increased to give a head that minimizes the flow of formation water into the hole.

The mud-pumping equipment on a conventional drilling rig is not suitable for aerating because it is extremely difficult to control with sufficient accuracy the amount of fluid used at the lower range of fluid volumes.

WATER SHUTOFF

As mentioned previously, the greatest single disadvantage to air drilling is penetrating water-bearing formations. The fluid entering the hole from such formations combines with the cuttings to form a gummy aggregate that may stick both to the drill pipe and to the walls of the hole. Eventually a layer is built up that reduces circulation and causes sticking of the drill pipe.

Many methods of water shutoff have been tried with varying degrees of success. The first method was the conventional cement squeeze, which has often been successful, but it has two disadvantages: (1) it normally requires 24 hours for the cement to set, after which the water used to displace the cement must be evacuated from the hole, and the hole must be dried, an operation that may take an additional 12 or 24 hours; (2) the water may hydrate some of the formations and cause swelling and even sloughing. Bentonitic shales are particularly dangerous.

The ideal method for water shutoff is one which requires the minimum rig time and causes no formation wetting. A considerable amount of work is being done to develop some type of plastic material that has a controllable setting time and a sufficiently low viscosity so that it can be forced into the formation under low pressure. It is preferable that the plastic be displaced with air, but if the available air pressure is insufficient, an adequate amount of water may be put in the drill pipe to give the necessary pressure increase. A valve arrangement placed on top of the squeeze tool can prevent the water from entering the hole.

Several materials that are being used currently on an experimental basis have promised the desired requirements, but at present how successful any of these will be is in question.

SAFETY

Air or gas drilling is not as safe as conventional drilling. When gas is used, there is a constant fire hazard due to the possibility of leaks in the supply line or around the stripper head. The gas must be exhausted at a considerable distance from the rig and should be burned at the end of the flow line. As a safety factor, a pilot light should be in continous operation on the flow line.

Air offers little or no fire hazard, but there is a danger of down-hole explosions and some danger of fire if oil or gas is encountered. If the annulus becomes restricted, or if a flow-line valve is closed, allowing a pressure build-up in the hole, conditions may develop that would cause an explosion. From practical experience it has been found that when the pressure in the annulus exceeds 600 pounds per square inch, the proper gas-air mixture may explode. There have been several instances where both drill pipe and casing have been damaged. One method of overcoming both the fire and explosion hazard is the consumption of the exhaust gases. The primary drawback to this procedure is the amount of additional equipment needed to cool and dehumidify the engine exhaust and to remove acids from the gas.

GEOLOGICAL CONSIDERATION

From the standpoint of the geologist evaluating a well being drilled with air, there are one or two new aspects that must be considered. In the first place, the cuttings arrive at the surface as a fine powder, and the conventional methods of sample identification generally will be ineffective. It takes some practice to identify the cuttings accurately. In a known area the color of the powdered material is almost as reliable a means of identification as can be obtained with the microscope.

A decided advantage to air drilling is that there is practically no lag, and the contamination of samples from different formations is reduced considerably.

It should also be remembered that the conditions are very similar to those which exist during a drill-stem test. It would be extremely difficult to by-pass any zone containing even a show of oil or gas.

In the preceding section several advantages and disadvantages relating to air drilling have been discussed. In the first place, where it is applicable, air drilling can reduce drilling costs greatly by increasing penetration rates and prolonging bit life. On the other hand, in some instances the cost of attempting to combat formation water may be excessive.

In a wildcat operation there is an increasing chance of blowouts in addition to fire and explosion hazards. Before attempting an air-drilling operation, an appraisal based on all known facts should be carefully made.

With the constantly increasing cost of drilling wells and the decreasing percentage of successful wildcats, it is becoming more important to take full advantage of any opportunity for lowering drilling costs. Air and gas drilling may be one answer. In several parts of the country it has already become an accepted method and will undoubtedly become popular in many other areas as soon as reliable water-shutoff methods are developed.

Chapter 37

SPECIAL APPLICATIONS OF DST PRESSURE DATA

C. A. Einarsen
J. P. Dolan
and
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INTRODUCTION

A drill-stem test is a temporary completion designed to sample the formation fluid and to establish the possibility of commercial production. Early pressure recording devices were used merely to verify proper operation of the testing tool. Until recently the accuracy of the pressure gauges has been insufficient for any reliable quantitative use of the recorded pressures. In view of the need for more reliable formation evaluation and as a result of the recent interest in exploration work employing the concept of hydrodynamic entrapment, (Hill, 1951, 1954; Hill and Knight, 1956; Hubbert, 1953) better pressure recording gauges are now in use. These devices can record pressure within 1 percent above 1000 psig and can detect differential pressures as low as ½ psig.

In addition to formation pressure, several other reservoir characteristics can be determined from DST charts; namely, well productivity, formation permeability, wellbore damage, and the possible existence of barriers (faults, pinchouts, changes in permeability, etc).

This chapter presents a practical method to interpret DST pressure charts for formation pressures and many other reservoir properties, a method that has been developed in analyzing approximately 4000 DST charts during the last five years. The techniques used are a composite of published articles on drill-stem testing (Black, 1956; Olson, 1953), together with well-known pressure build-up analysis methods.

THEORY

It has been shown (Muskat, 1937; Horner, 1951) that the following equation may be used for analysis of pressure build-up curves:

$$P_o - P_w = 162.6 \frac{q\mu}{kh} \log \left(\frac{t_o + \theta}{\theta} \right) \quad (1)$$

When this equation is applied to the curves obtained in drill-stem testing, the assumptions and boundary conditions are more nearly realized than in conventional flow and build-up tests on producing wells. Zak and Griffen (1957) have recently discussed in detail the use of this equation in analyzing DST charts.

One of the problems with DST curves is the lack of reservoir data for precise analysis. Therefore, it is necessary to develop empirical rules and field methods for analyzing DST charts in quantity. For this reason, the empirical methods presented in this paper have been developed, and their derivation is found in Appendices A and B.

METHOD USED FOR ACCURATE READING OF DRILL-STEM TEST CHARTS

In order to apply the pressure build-up theory to DST charts, it is necessary to obtain a digitized expression for the pressure and time data recorded by the pressure gauge. These data may be either provided by the service company or interpolated by projecting a photographic reproduction of the chart against a cartesian wall screen and converting the scale readings to pressure and time values based on the reported readings of key points.

The authors have used an optically linear opaque projector and a standard cross-section-millimeter paper screen to tabulate intermediate pressure points between the key points normally reported on the charts. Use of this technique depends upon correct calibration of the gauges.

Comparing the measured mud pressure with mud weight and the measured flowing pressure against recovery weight are independent methods for checking gauge accuracy. The variation between measured mud pressures and estimated mud pressures, which are calculated from mud weight and depth, usually check within 2 percent, as shown in Figure 37-1.

RESULTS

Pressure Extrapolation

Experience in plotting a large number of DST charts on semi-logarithmic paper has shown that a straight line is usually obtained when the indicated kh/μ is greater than 10 md ft/cp. In the ranges of kh/μ less than 10 md ft/cp, curved plots are usual. Curved developments also occur when non-radial flow is present. Figure 37-2,

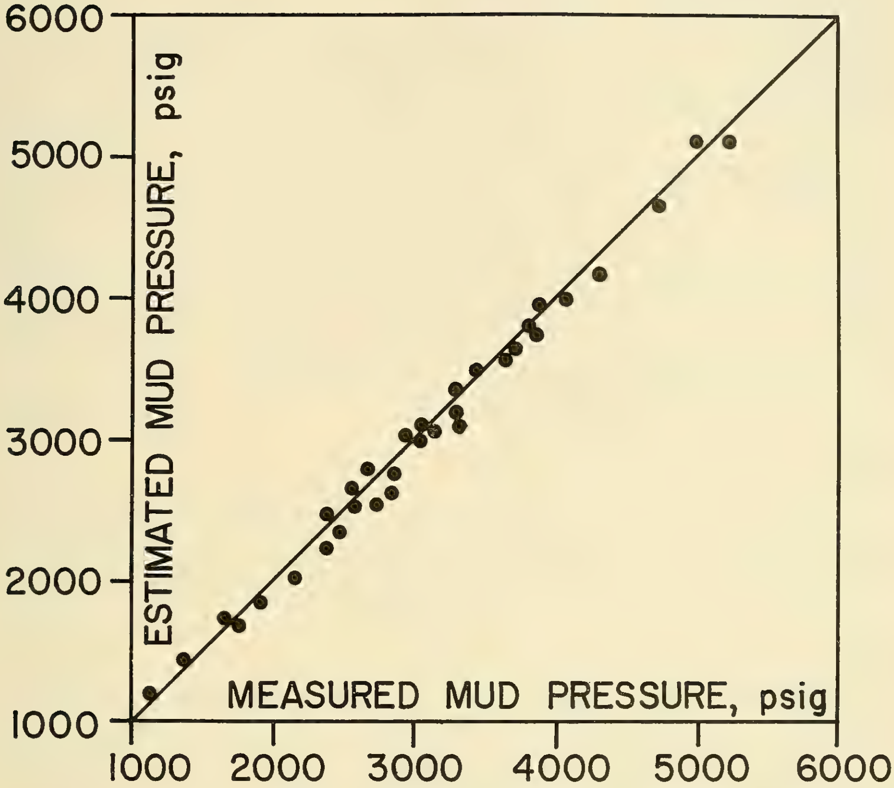

FIGURE 37-1. Measured mud pressures compared with estimated mud pressure.

which is an example of the result that can be expected, illustrates the comparison of formation pressures obtained by DST 44 days before completion and by extended pressure surveys. Fortunately in this case, two pressure surveys were available for comparison.

There are several causes of error in extrapolation to original pressure. Aside from a multiplicity of tool, packer, and gauge troubles, which can usually be identified, there is the problem of low-capacity (kh) formations. The production of even a small quantity of fluid is frequently enough to draw the formation pressure down, so that a prohibitively long shut-in time is necessary to obtain a usable build-up curve. The initial shut-in pressure technique is used to minimize the effects of excessive fluid production. Entrapped mud pressure is bled off, presumably just enough to equalize the formation pressure, by opening the formation into a limited air chamber sealed off from the main drill pipe. This technique is very useful in medium-to-good permeability formations, since a level formation pressure is quickly obtained. In the low-capacity (kh) formations, even the initial shut-in will fail to develop in reasonable time. Mud leakage from the annulus also produces abnormal pressures. Again it is the low-capacity (kh) formation which is susceptible to mud-leakage effect. The measurement of pressure in the low-capacity (kh) formation is a continuing problem that merits considerable attention.

Closely related to low-capacity (kh) is the question of proper shut-in time. Other things being equal, the error in extrapolation is proportional to the amount of log $(t + \theta)/\theta$ remaining at the end of the shut-in period. Figure 37-3 illustrates the relationship between extrapolation error and shut-in times. *One of the greatest causes of non-usable DST pressure charts is insufficient shut-in time* relative to the flowing time and capacity (kh) of the formation. The lower the capacity of the formation, the longer the shut-in time must be to obtain an accurate extrapolated pressure.

Effective Permeability

The effective formation permeability may also be determined within limits from the DST chart by using the well-known methods (Horner, 1951; Miller, Dyes, and Hutchinson, 1950; van Everdingen, 1953; Hurst, 1953) for pressure

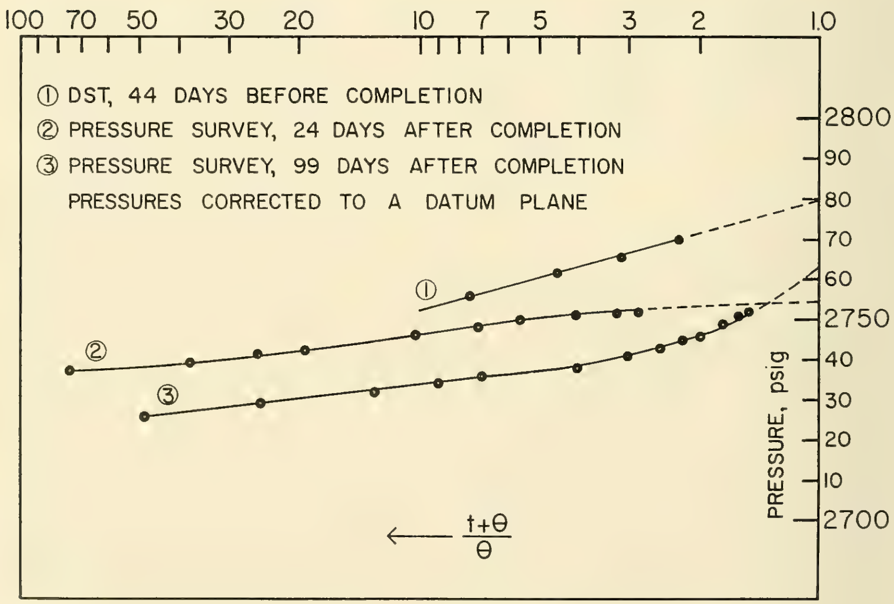

FIGURE 37-2. DST pressure build-up curve compared with conventional pressure build-up curves.

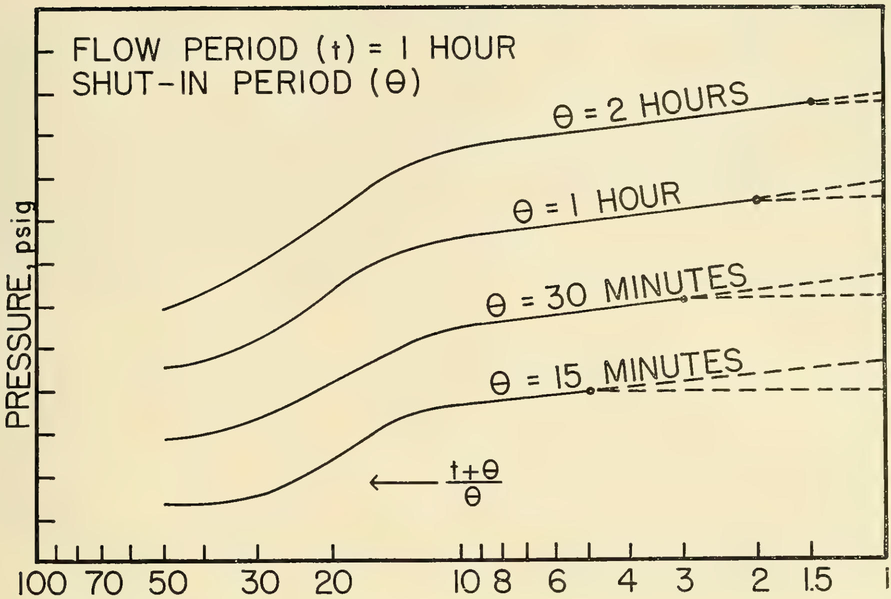

FIGURE 37-3. The effect of shut-in time on the accuracy of extrapolated pressure.

build-up curves. The use of an average production rate determined from the total recovery divided by the flowing time is generally sufficient for use in the formula

$$\frac{kh}{\mu} = 162.6 \frac{q_a}{\Delta P} \tag{2}$$

Unless the flowing curve is approximately straight, indicating constant production rate, Equation 2 will not be strictly correct (see Appendix A). Fortunately, accuracy requirements on permeability are not strict, and the appoximate value obtained from a DST is useful. Since the permeability so determined represents the average effective value for an entire drainage area, it may in fact be a better value than the permeability reconstructed from isolated core plugs from the section. In vugular and fractured porous zones, the effective permeability of the drainage area is all important and cannot be measured except by testing.

Field Method For Calculating Effective Permeability

A practical field method for estimating effective permeability is illustrated in Figure 37-4. It is necessary to have a successful duel shut-in pressure test, in which the initial shut-in curve is nearly leveled out. The final shut-in pressure need only be developed to about three-fourths of the way between the final flowing pressure and the initial shut-in pressure. The procedure is as follows:

Extend the initial shut-in pressure curve until it intersects the pressure ordinate where $(t + \theta) / \theta = 1$. Connect this point with the final shut-in pressure point which has been plotted according to the value of $(t + \theta)/\theta$ from the open time (t) and shut-in time (θ). Extend this line until it intersects the pressure ordinate where $(t + \theta)/\theta = 10$. Using this ΔP across one logarithmic cycle, calculate the effective permeability (kh/μ) according to Equation 2.

As a specific example and referring to Figure 37-4; DST: open 45 minutes. Shut in 15 minutes. Recovery: 540 ft water in 4½ in. drill pipe. Sand thickness: 20 ft. Estimated fluid viscosity: 1 cp. ISIP = 1800 psig. FSIP = 1620 psig. Average production rate:

$$q = \frac{540 \times .0142 \times 1440}{45} = 245 \text{ B/D},$$

$$(t + \theta)/\theta = \frac{45 + 15}{15} = 4.0$$

Connecting the ISIP with FSIP and extending this line until it intersects the pressure ordinate where $(t + \theta)/\theta = 10$,

$$P_{10} = 1500 \text{ psig}$$

$$Ps - P_{10} = 300 \text{ psig/cycle}$$

$$\frac{kh}{\mu} = \frac{162.6(245)}{300} = 133 \frac{\text{md ft}}{\text{cp}}$$

$$\frac{k}{\mu} = 6.65 \text{ md/cp}$$

$$k \cong 7 \text{ md} \pm$$

Therefore, from the reported data we are able to calculate the effective permeability. This calculation can be performed at the well immediately after removing the chart from the testing tool.

Productivity Index and Wellbore Damage

Productivity index and damage ratio can also be determined from DST data. Two values of productivity index are obtainable. The first comes from the flow curve and is determined by the amount of fluid recovered, the length of flowing time, and the pressure differential between the flowing pressure and the true formation pressure. The second value of productivity index comes from an analysis of the final shut-in curve. The first value of productivity index is affected by any kind of wellbore damage, because during the flow period the fluid recovered had to pass through the damaged zone. The second value of productivity index is nearly independent of damage because essentially no flow takes place during the final shut-in time.

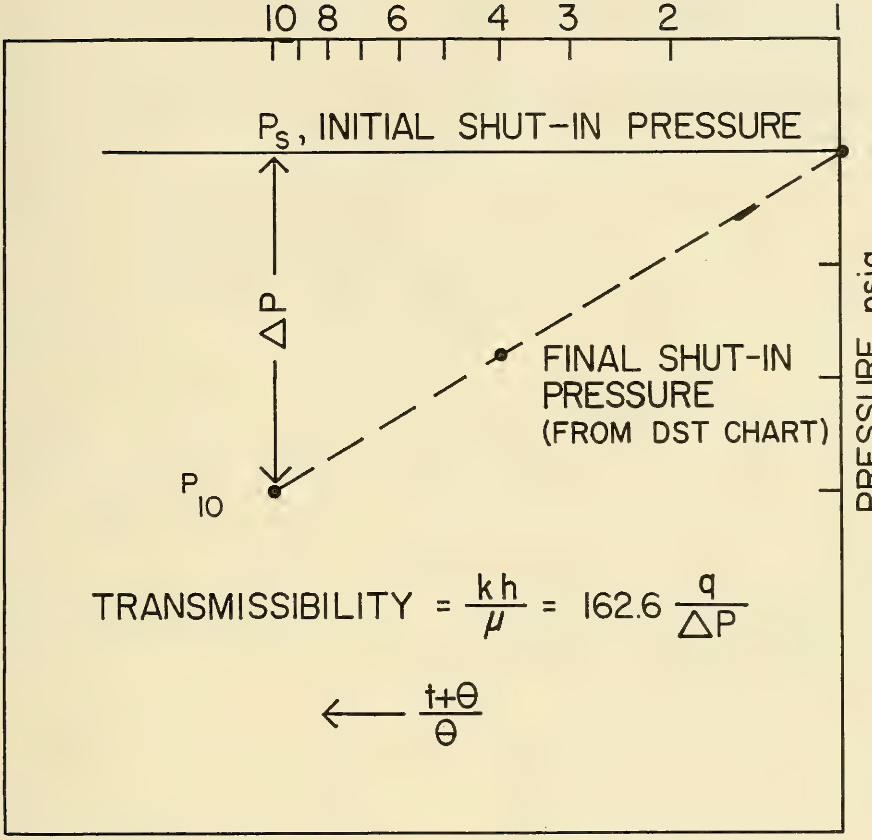

FIGURE 37-4. Technique for field interpretation of effective permeability.

The ratio between these two values of productivity index is therefore indicative of wellbore damage. This damage is commonly caused by a mud filtrate water block on the formation face or pressure loss across perforations in the anchor or across the testing tool.

Field Method For Calculating Damage Ratio

Although more precise methods are described in the literature, (van Everdingen, 1953; Hurst, 1953; Arps, 1955) the damage ratio may be calculated at the well site immediately after the DST chart is recovered by using the following empirical equation (see Appendix B):

$$\text{D.R.} = .183 \frac{P_s - P_f}{\Delta P} \tag{3}$$

Following the same field method for permeability determination, $a\Delta P$, across one logarithmic cycle is determined. The final flowing pressure, P_f, is obtained directly from the chart. Figure 12-5 illustrates the procedure used.

As a specific example: DST: Open 45 minutes. Shut-in 15 minutes. Recovery: 100 ft. mud with show of oil.

$$\text{ISIP} = 2780 \text{ psi} \quad \text{FSIP} = 2720 \text{ psi} \quad \text{FFP} = 50 \text{ psi.}$$
$$P_{10} = 2680 \text{ psi.} \quad Ps - P_{10} = 100 \text{ psi.}$$

$$\therefore \text{D.R.} = \frac{.183(2780 - 50)}{(2780 - 2680)} = 5.$$

The above calculation indicates that approximately five times as much fluid would have been recovered had no damage occurred, or if the tool had remained open a sufficient length of time to sample the formation more effectively. Had no damage occurred or had the tool been left open longer, the next influx of formation fluid into the testing tool would presumably have been oil. The operator, at this point, may desire to retest the formation to prevent the possibility of passing up a potentially productive zone. By determining the formation damage immediately after the test, the operator's evaluation of the productivity of the tested interval may be considerably different from that based on recovery alone and may warrant retesting the zone, a change in the drilling schedule, or a change in completion interval.

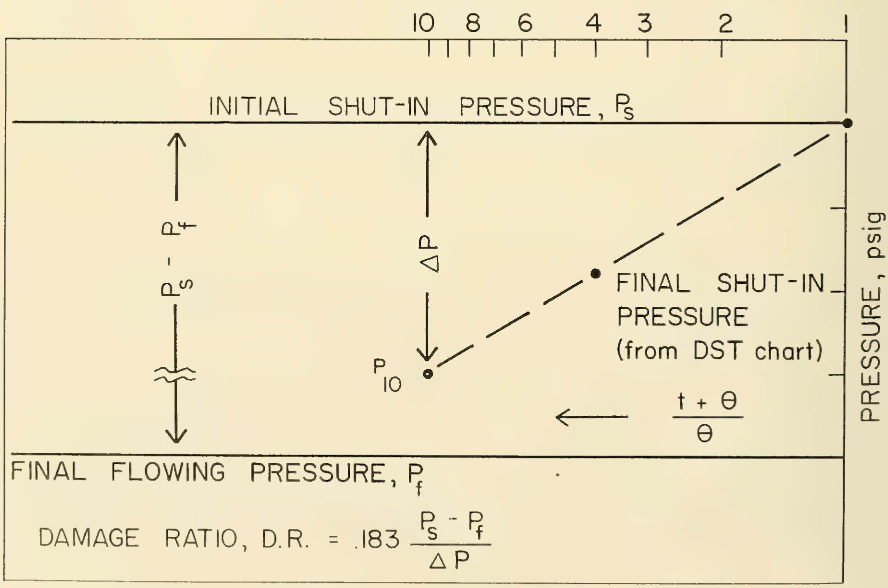

FIGURE 37-5. Technique for field interpretation of damage ratio.

In addition to the above field methods, permeability and damage effect on DST charts can also be qualitatively evaluated by visual inspection. Figure 37-6 shows the effect of permeability and damage on the actual appearance of the flowing and shut-in curves. These charts are facsimiles based on earlier analyzer studies of the process (Bruce, 1943; Dolan and Hill, 1955). The chief

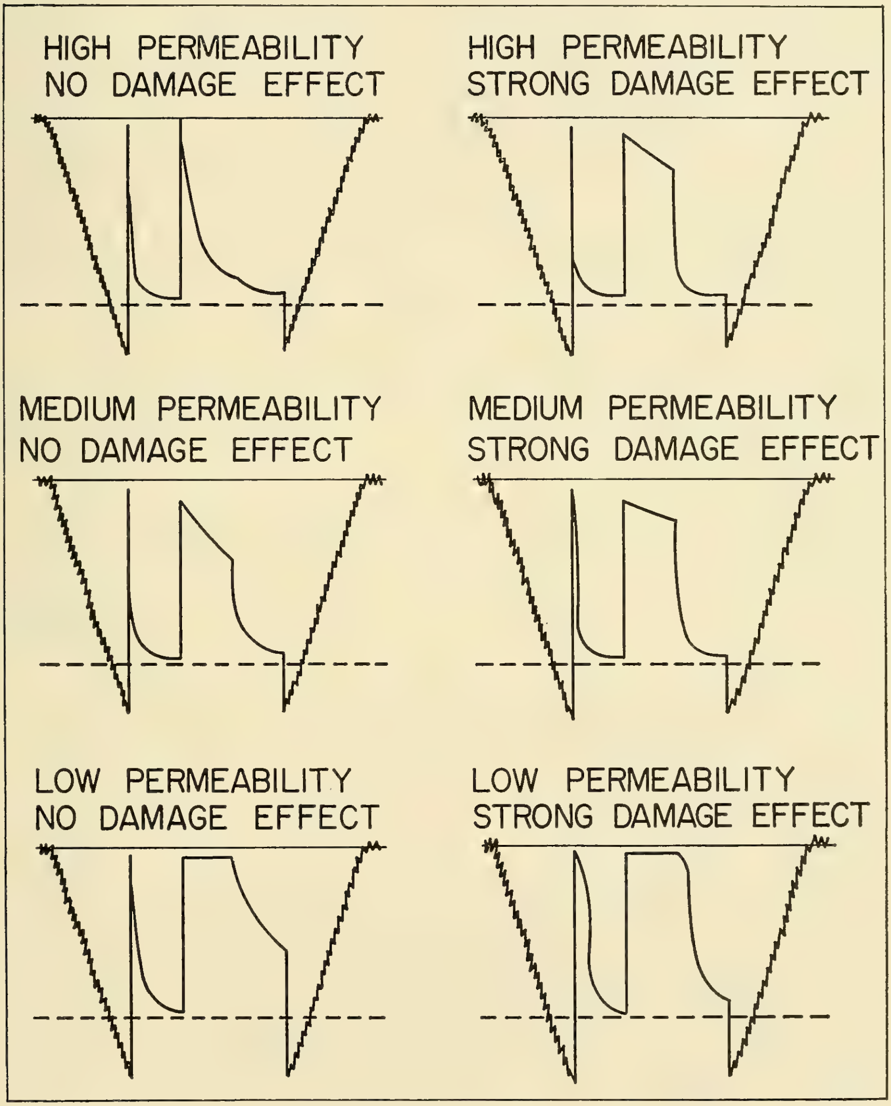

FIGURE 37-6. Typical DST charts illustrating effects of permeability and damage.

effect of damage is in reducing recovery. The shut-in rate is also faster where a damage effect exists.

Barrier Detection

In principle, the detection of changes in transmissibility, kh/μ, in the vicinity of the wellbore can be determined by study of the pressure build-up curves (Horner, 1951). When formation conditions are favorable, DST charts may be analyzed to detect nearby barriers. For example, in the case of a linear barrier fault, the expected result is a break in the linearity of the plot on semi-logarithmic paper. The early part of the curve will have a slope, ΔP, in psi/cycle exactly one-half the ΔP of the latter part of the curve. In practice, an exact one-half ratio is not measurable. Figure 37-7 shows an actual DST curve indicating the possibility of barrier interference. The ISIP appears reliable. The permeability measured on the latter part of the shut-in curve, is in agreement with core data on the interval tested. The test recovered 1600 ft of free oil while the off-set well was tested dry in the same zone. Had an initial shut-in pressure not been taken and had the final shut-in time been insufficient, the change in the slope in the latter part of the pressure build-up curve would not have been observed and the detection of the barrier would not have been possible.

Extending the pressure build-up analysis to DST charts for barrier detection presents the following difficulties.

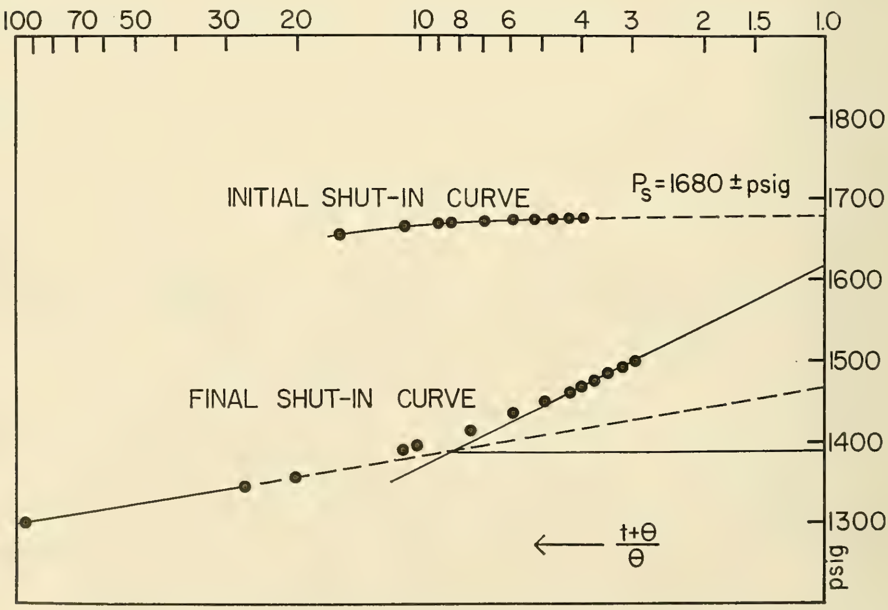

FIGURE 37-7. DST pressure build-up curves indicating possible barrier.

1. The distance of penetration can be shown to be proportional to the flowing time. An empirical relationship, $b^2 = kt$ (where b is the distance to the barrier in feet, and k is the permeability in md) may be used to estimate the range of penetration detectable on a DST chart (see Appendix C). For most drill-stem tests, the capacity (kh) of the formation will be unfavorable for large radial penetration within reasonable flowing time.

2. Production rate is not constant. Effects similar to the break in the plot can also be caused by a decreasing production rate (see Appendix A).

3. Reservoir characteristics do not agree with the simplified assumptions. Since the analysis is based on a simplified radial-flow picture, any departure from the assumptions can obviously cause curvature, which could be mistaken for breaks.

RECOMMENDATIONS

1. For accurate pressure readings, use proper clock speeds and pressure elements to get the maximum size pressure curve on the DST chart.

2. Always take a double shut-in test. This will permit a much more accurate extrapolated formation pressure and may permit the detection of changes in formation transmissibility or barriers in the event the tool is not shut in a sufficient length of time.

3. Where practical, set the flowing time on the basis of the observed blow. If the blow indicates that substantial recovery has been obtained, there is no need for a longer flow period; therefore, the tool may be shut in at that time. The weaker the blow, the longer the tool must be left open to sample the formation effectively.

4. The final shut-in time should be at least equal to the flowing time if an accurate extrapolated formation pressure is to be obtained and if nearby changes in transmissibility are to be detected. The final shut-in time should be as long as possible but should also be consistent with rig-time cost and safe hole conditions.

5. The lower the permeability of the zone to be tested, the longer should be the shut-in time. If the capacity (kh) is expected to be below 10 md-ft, a long initial shut-in time ranging up to two hours is recommended. For capacities above 10 md-ft, a shut-in time of 30 minutes is usually sufficient.

6. Measure the mud weight several times during the circulation period immediately prior to running the DST in order to get an accurate and representative mud weight over the entire length of the well.

7. Record accurately inside diameters of drill collars and drill pipe used in the testing string; the location, relative to the bottom of the hole, of all pressure gauges used; and the number and location of packers used.

NOMENCLATURE

Symbol	*Description*	*Used Field Units*	*CGS Units*
a	constant rate of change of production rate	B/D/D	cc/sec^2
b	distance to a linear barrier	ft	cm
c	compressibility	vol/vol/atm	vol/vol/atm
D	$(t_o + \theta) / \theta$ at a specific point	dimensionless	dimensionless
D.R.	damage ratio	dimensionless	dimensionless
$(\text{D.R.})_o$	normal damage ratio, zero skin	dimensionless	dimensionless
$(\text{D.R.})_m$	measured damage ratio	dimensionless	dimensionless
δ	θ / t_o, a ratio	dimensionless	dimensionless
e	base of natural logarithms	dimensionless	dimensionless
E	error in pressure	psi	atm
f	porosity fraction	dimensionless	dimensionless
FFP	final flowing pressure	psi	atm
FSIP	final shut-in pressure	psi	atm
h	sand thickness	ft	cm
ISIP	initial shut-in pressure	psi	atm
j	a subscript number	dimensionless	dimensionless
k	permeability	md	darcies
kh	capacity	md ft	darcy-cm
kh/μ	transmissibility	md ft/cp	darcy-cm/cp
ln	logarithm base e	dimensionless	dimensionless
log	logarithm base 10	dimensionless	dimensionless
μ	viscosity	cp	cp
N	number of logarithmic cycles	dimensionless	dimensionless
n	number of differential flow periods	dimensionless	dimensionless
P	pressure	psi	atm
P_f	flowing pressure	psi	atm
P_o	pressure at the infinite boundary	psi	atm
P_s	extrapolated formation pressure	psi	atm
P_w	pressure at the wellbore	psi	atm
P_{10}	pressure at the point where $(t + \theta)/\theta = 10$	psi	atm
ΔP	pressure difference over one logarithmic cycle	psi/cycle	atm/cycle
ΔP_{form}	pressure drop across the formation proper	psi	atm
ΔP_{total}	total pressure across a wellbore	psi	atm
P.I.	productivity index	B/D/psi	cc/atm sec
$(\text{P.I.})_m$	measured productivity index	B/D/psi	cc/atm sec
q	varying production rate	B/D	cc/sec
q_a	average production rate	B/D	cc/sec
q_1	initial production rate	B/D	cc/sec
$q_2, q_3,$	different but constant		
q_j	production rates	B/D	cc/sec
q_n	final production rate	B/D	cc/sec
r	radial distance from the well	ft	cm
r_w	wellbore radius	ft	cm
S	skin resistance	psi day/bbl	atm/sec/cc
t	flowing time	minutes	sec
t_o	total flowing time	minutes	sec
Δt	differential flowing periods	minutes	sec
θ	shut-in time	minutes	sec
X	arbitrary variable		

8. Using the simplified methods outlined in this chapter, calculate the effective permeability and wellbore damage as soon as the DST chart has been recovered. These calculations may greatly alter the evaluation of the zone tested, which may be based on recovery alone, and may warrant retesting the zone, a change in the drilling schedule, or a change in the completion interval.

CONCLUSIONS

1. Aside from limited possible application to low-capacity (kh) formations, a true original formation pressure can be determined by drill-stem testing long before completion and before any drawdown due to production takes place.

2. Effective permeability and wellbore damage can be calculated at the well site by using the simplified methods presented in this chapter.

3. Barriers such as faults, pinchouts, changes in formation permeability, etc., can sometimes be detected by proper analysis of DST charts, provided formation conditions are favorable.

Acknowledgment

The authors wish to express their appreciation to Petroleum Research Corp. for permission to publish this chapter.

APPENDIX A

Aside from the difficulties in reducing reservoir conditions to the usual simplified constant-parameter radial flow picture, there is the question of the effect of non-constant production rate, which obviously exists during many drill-stem tests. It is the practice to approximate the varying production rate problem by breaking the flow period, t_o, into a finite series of sub-periods, Δt, each having a different but constant production rate, $q_1, q_2, q_3 \ldots q_n$. Then, if the superposition theorem is used, the basic equation becomes:

$$P_o - P_w = \frac{\mu}{4\pi kh}\left[\ln\left(\frac{n\,\Delta t + \theta}{(n-1)\,\Delta t + \theta}\right)^{q_1} + \ln\left(\frac{(n-1)\,\Delta t + \theta}{(n-2)\,\Delta t + \theta}\right)^{q_2} + \ldots + \ln\left(\frac{\Delta t + \theta}{\theta}\right)^{q_n}\right]. \quad (4)$$

Assuming

$$\frac{r^2 f \mu c}{4\,k\,\theta} < .01\,,\; q_j = \text{constant}.$$

It can be shown that the superposition of solutions given in Equation 4 can be expressed as:

$$P_o - P_w = \frac{\mu}{4\pi kh}\left[\ln\frac{(t_o+\theta)^{q_1}}{\theta^{q_n}} + \sum_{j=1}^{n-1} \ln\left\{(n-j)\,\Delta t + \theta\right\}^{q_{j+1}-q_j}\right] \tag{5}$$

If the number of sub-periods, n, is made indefinitely large, then Equation 5 becomes:

$$P_o - P_w = \frac{\mu}{4\pi kh}\left[\ln\frac{(t_o+\theta)^{q_1}}{\theta^{q_n}} + \int_o^{t_o} \frac{dq}{dt}\ln(t_o+\theta-t)\,dt\right] \tag{6}$$

provided dq/dt exists as a continuous function of t. Equation 6 is the solution for non-constant production rate, q. The following case is considered as an illustration:

Let: $dq/dt = a =$ constant,

The integral in Equation 6 may be evaluated

$$P_o - P_w = \frac{\mu}{4\pi kh}\left[\ln\left(\frac{t_o+\theta}{\theta}\right)^{q_a} + (q_n - q_1)\left\{\left(\frac{t_o+2\theta}{2t_o}\right)\ln\left(\frac{t_o+\theta}{\theta}\right) - 1\right\}\right] \tag{7}$$

where $q_a = q_1 + \frac{q_n - q_1}{2}$ is the average production rate.

The case where dq/dt is a constant is a fair approximation to many DST curves which have a varying production rate, q. The error may be expressed as

$$E = \frac{(q_n - q_1)\,\mu}{4\pi kh}\left[\frac{t_o+2\theta}{2t_o}\ln\left(\frac{t_o+\theta}{\theta}\right) - 1\right] \tag{8}$$

which is of the form:

$$E = \frac{(q_n - q_1)\,\mu}{4\pi kh}\left[(\tfrac{1}{2}+\delta)\ln\left(1+\frac{1}{\delta}\right) - 1\right];\ \delta = \frac{\theta}{t_o} \tag{9}$$

$$\text{and, since } \left(1 + \frac{1}{\delta}\right)^{\frac{1}{2} + \delta} \rightarrow e \text{ as } \delta \rightarrow \infty \ .$$

then the error will vanish at infinite shut-in time.

In terms of percentage, the error in using the average production rate, q_a, in Equation 2 instead of Equation 7, which corrects for varying production rate, may be expressed as follows:

$$100 \times \frac{E}{P_o - P_w} =$$

$$\frac{(q_n - q_1)\left[\left(\frac{1}{2} + \delta\right) \ln\left(1 + \frac{1}{\delta}\right) - 1\right] \times 100}{q_a \ln\left(1 + \frac{1}{\delta}\right)} \tag{10}$$

Figure 37-8 illustrates how much difference the error will make. As long as the difference in initial and final production rate is not extreme, use of the average production rate will be a good approximation for the latter part of the plot. Empirically this fact was borne out in the electric analyzer studies of the

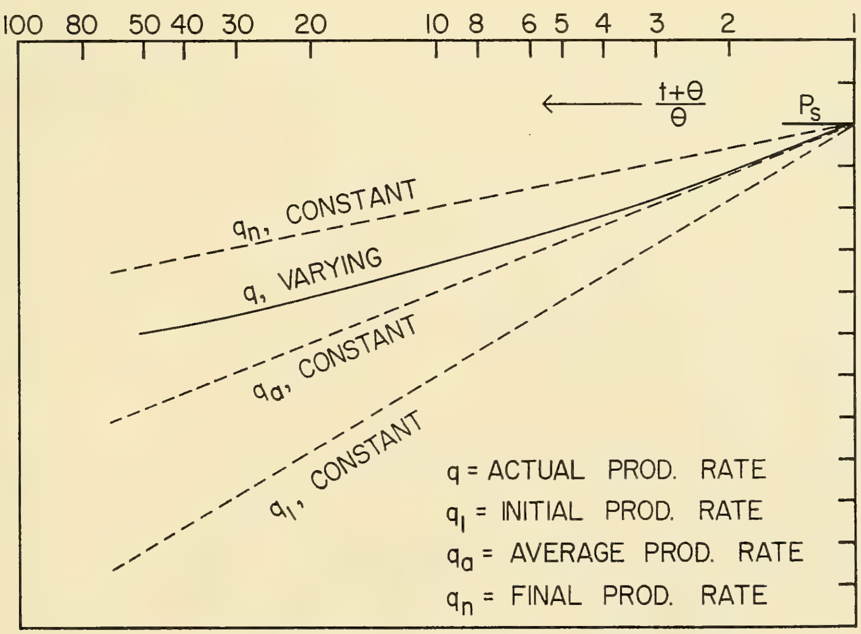

FIGURE 37-8. Influence of production rate of pressure build-up.

DST process earlier (Dolan and Hill, 1955). All other things being equal, if shut-in curves from tests having a production rate of q_1, q_n and q_a constant through the flow period are compared with a curve having a production rate changing with time, $dq/dt = a$, from q_1 to q_n, the varying production-rate curve will approach the average production-rate curve with negligible error as the shut-in time increases.

APPENDIX B

The damage ratio defined in this chapter is an empirical factor intended for practical immediate evaluation when most of the necessary data for precise determinations are unavailable. The relation of conventional treatments in the literature to the damage ratio here defined is explained as follows: The equation for total pressure drop across the wellbore is

$$\Delta P_{\text{total}} = -\frac{q\mu}{4\pi kh} Ei\left(-\frac{r_w^2 f\mu c}{4kt_o}\right) + qS, \tag{11}$$

where $Ei(-X) = -\int_x^\infty \frac{1}{u} e^{-u}\, du$, which may be

approximated as $Ei(-X) \cong \ln X + .5772$ if $X < .01$.

Damage ratio, D.R., is defined as the dimensionless ratio of kh/μ to instantaneous P.I., where the P.I. is taken to mean the measured ratio of production rate to differential pressure, P.I. $= q/(P_s - P_f)$.

$$\text{D.R.} \frac{kh(P_s - P_f)}{\mu q} \tag{12}$$

This D.R. is measurable from the flowing and shut-in curves on a DST chart. Replacing $kh/\mu q$ with $\frac{\ln 10}{4\pi\Delta P}$ from the shut-in curve, the following equation is obtained.

$$\text{D.R.} = (.183)\frac{P_s - P_f}{\Delta P} \tag{13}$$

Using Equation 12, one may define a D.R. from Equation 11 for two cases. Case I: $S = 0$, the normal D.R., without skin damage.

$$(\text{D.R.})_o = -\frac{1}{4\pi} Ei\left(-\frac{r_w^2 f\mu c}{4kt_o}\right) \tag{14}$$

Case II: $S \neq 0$, the measured D.R. including skin damage.

$$(\text{D.R.})_m = -\frac{1}{4\pi} Ei\left(-\frac{r_w^2 f \mu c}{4kt_o}\right) + \frac{kh}{\mu} S \qquad (15)$$

$$\text{or} \quad (\text{D.R.})_m = (\text{D.R.})_o + \frac{kh}{\mu} S\,. \qquad (16)$$

Furthermore, the pressure drop over the damaged region will be

$$qS = \frac{q\mu}{kh}\left[(\text{D.R.})_m - (\text{D.R.})_o \right] \qquad (17)$$

Since we are normally interested in what percentage qS is of the total:

$$\frac{qS \times 100}{\Delta P_{\text{total}}} = \left[\frac{(\text{D.R.})_m - (\text{D.R.})_o}{(\text{D.R.})_m}\right] \times 100 \qquad (18)$$

If $(\text{D.R.})_o$ can be determined, Equation 18 may be solved, since $(\text{D.R.})_m$ is measurable.

From Equation 14, $(\text{D.R.})_o$ can be evaluated if the data are available.

Using reasonable values, it appears that $(\text{D.R.})_o = 1$ is not an unreasonable upper limit for DST curves.

Therefore, if $(\text{D.R.})_o$ is assumed to equal 1 as an arbitrary reference,

$$qS = \frac{(\text{D.R.})_m - 1}{(\text{D.R.})_m} \Delta P_{\text{total}} \qquad (19)$$

$$\Delta P_{\text{form}} = \frac{1}{(\text{D.R.})_m} \Delta P_{\text{total}} \qquad (20)$$

$$\frac{q}{\Delta P_{\text{form}}} = (\text{D.R.})_m \frac{q}{\Delta P_{\text{total}}} \qquad (21)$$

$$\text{P.I.} = (\text{D.R.})_m \times (\text{P.I.})_m \qquad (22)$$

As the result in Equation 22 shows, the theoretically maximum (P.I.) should be at least $(\text{D.R.})_m$ times the measured $(\text{P.I.})_m$.

In relating this factor to the published work of van Everdingen, Hurst, Miller, Dyes, Hutchinson, and Arps, it is evident that they are all equivalent It is noteworthy that the assumption $(\text{D.R.})_o = 1$ is equivalent to an assignment of $N \simeq 5.5$ cycles in the Arps' graphical plotting method. The field example cited by Hurst may be worked with this method and close agreement will be obtained. This is coincidental because the values of

$$Ei\left(-\frac{r_w^2 f\mu c}{4kt_o}\right)$$

happen to be consistent with $(\mathrm{D.R.})_o = 1$.

APPENDIX C

Barrier Detection

The theory of barrier detection stated by Horner (1951) is based on the superposition of solutions of two equations, one for the well itself, and the second for its image reflected from the linear barrier at a distance, b, from the producing well. Horner concludes that the following equation is satisfied at the intersection of the two straight lines:

$$-Ei\left(-\frac{b^2 f\mu c}{kt_o}\right) = \ln\left(\frac{t_o+\theta}{\theta}\right) \tag{23}$$

Let $D = \dfrac{t_o+\theta}{\theta}$ at the intersection of the two straight lines.

Assuming that $\dfrac{b^2 f\mu c}{kt_o} < .01$;

$$\text{then} \qquad -\left[\ln\frac{b^2 f\mu c}{kt_o} + .5772\right] = \ln D\,; \tag{24}$$

$$\text{then } b^2 = \frac{1}{1.783}\,\frac{kt_o}{f\mu cD}\,, \tag{25}$$

which is in cgs units.

Converting to field units,

$$b^2 = 3.622 \times 10^{-5}\,\frac{kt_o}{f\mu cD} \tag{26}$$

Selecting typical values for the reservoir terms,

$f = 10^{-1}$

$\mu = 1$ cp

$c = 3.6 \times 10^{-5}$ atm^{-1}

$D = 10$

Then Equation 8 becomes

$$b^2 \simeq kt_o \tag{27}$$

This relationship may be used to approximate the radial distance from a wellbore that a barrier can be detected on a DST chart. The permeability, k, is in md, and the flow time, t_o, is in minutes. For example, if the effective permeability were 100 md, and the total flowing time were 100 minutes, then it would be unreasonable to expect the detection of barrier interference at a range greater than 100 ft.

Reprinted from the Journal of Petroleum Technology and Petroleum Transactions, AIME, v. 210, p. 318-324 (Nov. 1957). T. P. 4667)

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Chapter 38

WELL-COMPLETION METHODS

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Mid-Continent District Study Committee on Completion Practices

Considerable thought was given to the time and order in which problems present themselves and require decisions in the process of drilling and completing wells. Operating and organizational procedures vary with companies, but the nature of the operation brings about a certain order that is generally followed. Completion operations are defined as those that occur from the time the drill first penetrates the pay zones until the well is placed on routine production; but some of the completion decisions must be made before the hole is started in order to tie into planning the drilling program. Responsibility for decisions may rest individually or jointly with the production personnel, reservoir-engineering personnel, drilling personnel, and general management. Figure 38-1 sets forth the general order in which these problems present themselves. The brackets to the left indicate the class of personnel involved in the choice to be made. Also, note that the choices to be made are indicated as applying to a proved producing area. A wildcat would be similar to the extent that areal information on geology, probable producing sands, and general data from nearby fields or wildcats can be applied.

The initial choice indicated is the style of bottom-hole setting. It is believed that this choice should be made before the well is started because of its influence on drilling procedure, casing programs, plans for special drilling-in equipment, and effect on contract well cost. This is indicated as a joint problem of the production engineer, who must produce the well and rework it when necessary, and the reservoir engineer, who has the best information on formation characteristics such as distribution of permeability and porosity. The bottom-hole settings are indicated as divided into two classes: set-through and set-on-top, with numerous subdivisions under each class. The points in favor of each class are shown in Figure 38-2.

The hole size is indicated as a matter for joint decision by the producing, reservoir, and drilling people, because it involves factors concerning all. Having reached this decision, drilling operations must begin to "deliver" a completion meeting these specifications. As indicated in the next bracket, drilling personnel are charged with decision on 12 items which are indicated by classification numbers. These items are analyzed separately in charts numbered accordingly that set forth factors involved in choosing the most satisfactory method of formation evaluation (fig. 38-3), drilling-in (fig. 38-4), etc. These charts are self-explanatory. Study of these factors results in a well-completion plan and cost estimate that must be submitted to management for approval. As indicated, this plan is weighed from a standpoint of cost vs. expected return and may be approved or modified. After final approval, the well is drilled and completed according to the plan, with such operating modifications as may be expedient during the process.

If completed as a commercial producer, an engineering follow-up is indicated by the next bracket. This work is carried out by two groups: mechanical engineering to check the performance of the surface and subsurface mechanical equipment chosen for the completion, and reservoir engineering to check the productive performance of the well on the basis of reservoir information, pressure-build-up tests, etc. This phase is a process of continuous observation of equipment and well performance; and the information, as indicated by the arrows, is fed back to selection of the type of completion to be used on subsequent wells in the field. Thus, the cycle of a continuous process of well-completion selection is completed.

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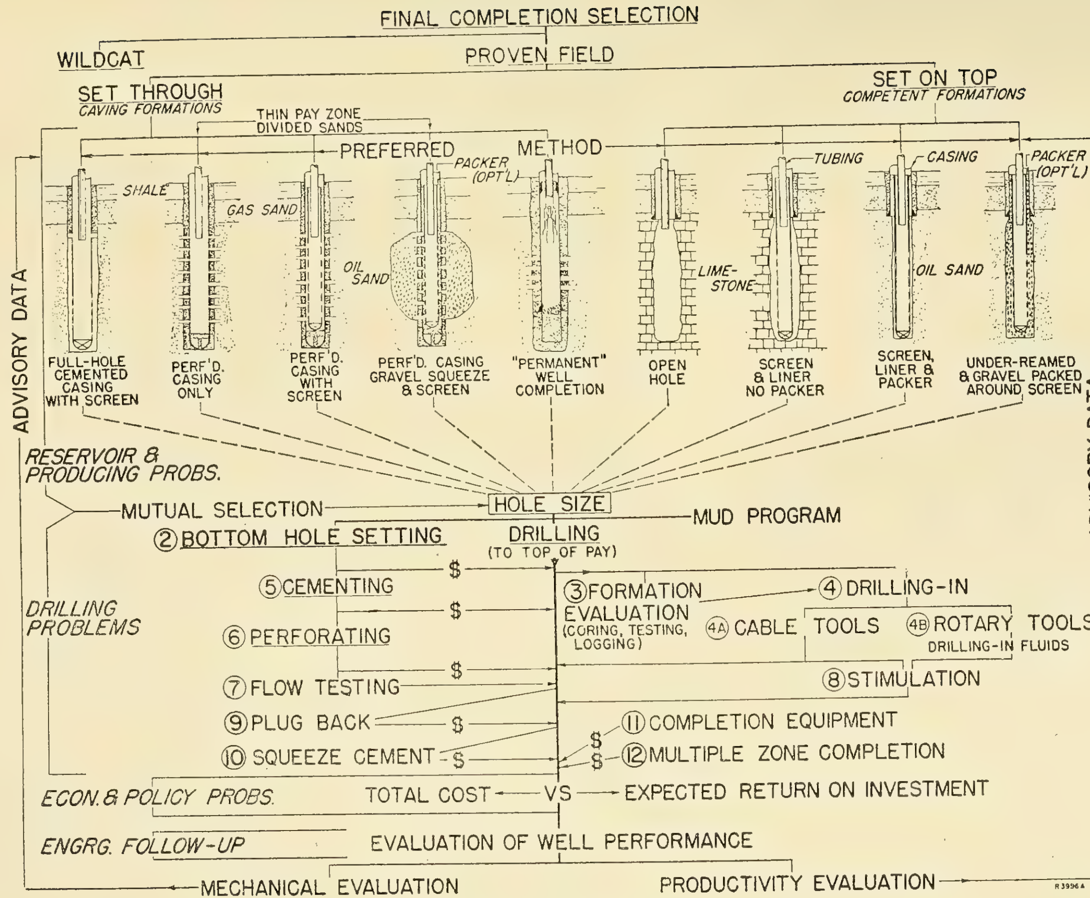


FIGURE 38-1. Master chart.

② COMPLETION SELECTION
FORM OF BOTTOM-HOLE SETTING

(Proved Field)*

Set Through
(Caving Formations)
(Divided Sands)
(Thin Pay Zones)
(Dual-zone Work)

Full-hole Cementing Casing with Screen†	Perforated† Casing Only	Perforated† Casing with Screen	Perforated Casing† Gravel, Squeeze, and Screen	Perforated Casing† and "Permanent-type" Completion
1. Wall support without cement penetration in crevices, vugs, or potted formation.	1. Selective formation treatment. 2. Multiple zones. 3. Gas-cap control. 4. Water-table control. 5. Sloughing-formation control.	1. Incompetent formation producing sand. 2. Amount of slot plugging material in produced fluid must be minor.	1. Extremely incompetent formation producing sand.	1. Quicker and cheaper completions. 2. Lower cost workovers or recompletions. 3. Usable mainly inside perforated casing. 4. Requires small and intricate tools. 5. Corrosive conditions may limit.

Set On Top
(Competent Formation)
(Zones of poor vertical permeability)
(If required for ease of formation decontamination)

Open† Hole	Screen, Liner,† No Packer	Screen, Liner,† and Packer	Under-reamed† and Gravel Packed around Screen
1. Low-cost. 2. Non-sloughing formations. 3. Non-continuous permeability. 4. Nitro-shooting areas 5. Avoids cement effects.	1. Low cost. 2. Supports sloughing formation (after nitro-shooting, etc.) 3. Avoids cement effect.	1. Sand producing formations. 2. Amount of slot-plugging material in produced fluid must be minor.	1. Sand producing formations. 2. Enlarged well-bore radius needed. 3. Prevention of sand bridging.

*In the case of wildcats, selection must be made on the basis of areal geological data to determine the most likely completion conditions. Proceed then as for proved field.

FIGURE 38-2. Selection of type of completion.

③ FORMATION EVALUATION METHODS

(Methods listed used in parallel—not necessarily alternate choices)

3A: Coring

Benefits:

1. Porosity and permeability analysis.
2. Apparent fluid saturations.
3. Water-oil and gas-oil contact
4. Visual examination.
   a. Lithology.
   b. Bedding planes.
   c. Inherent fractures.
   d. Physical rock characteristics.
5. Laboratory evaluations.
   a. Field reserves and recovery.
   b. Recovery methods (flood, repressuring, etc.).
   c. Effects of down-hole process agents (detrimental or beneficial to permeability and porosity).
6. Coring process may:
   a. Aid in straightening hole.
   b. Provide rat hole for better drill-stem test packer seat.
7. May speed penetration (diamond coring).

Limitations:

1. May recover contaminated and misleading formation samples.
2. Uncertain recovery (some formations).
3. Usually more expensive penetration than drilling.
4. Usually requires reaming before drilling ahead.
5. Fluid circulation restrictions.

CORING METHOD SELECTION

ROTARY

Benefits:

1. Operates in high-pressure zones.
2. Long cores.

Limitations:

1. Damage—fluid to cores
2. Damage—fluid to formation.

CORE BARREL

CONVENTIONAL (Standard or diamond head)

Benefits:

1. Adaptable—most competent formations.
2. Larger-diameter cores (good ratio, core volume to mud cake).
3. No special surface equipment.
4. Leaves no junk in hole.
5. Faster penetration (diamond head).
6. Maximum recovery.
7. Mechanically simple.

Limitations:

1. Greater amount of rig time usually required (round trips
2. Requires junk-free hole.
3. Usually requires reaming

WIRE-LINE

Benefits:

1. Adaptable to coring long sections (minimizes round trips; may speed overall penetration rate).
2. Rapid sample examination (without pipe round trips).
3. Leaves no junk in hole.

Limitations:

1. Special surface equipment.
2. Smaller core diameter (fair ratio, core volume to mud cake).
3. Often less recovery than conventional (fair recovery).
4. Requires reaming.
5. Mechanically more complicated.

SIDE-WALL

Benefits:

1. Permits up-hole formation samples.
   a. Spot check on uncored zones.
   b. Check on electrical logs.
2. Minimum rig time.
3. Multiple samples at same level.

Limitations:

1. Poor geological information.
2. Limited to relatively soft formations.
3. Minimum recovery.
4. Small samples (poor ratio, core volume to mud cake).
5. Frequently leaves junk.
6. Special surface equipment.
7. No opportunity to change drilling fluid.
8. Mechanically complex.

CABLE-TOOL

Benefits:

1. Low cost (where usable).
2. Low fluid head on formation.
3. Quick means of sample examination.
4. Simplicity.

Limitations:

1. Relatively low-pressure zones only.
2. Poor recovery.
3. Small samples.
4. Limited geological information.

TECHNIQUE

STANDARD CABLE TOOL

Benefits:

1. As fast as regular drilling.
2. Simple operation.
3. Can continuously core.

Limitation:

1. Broken samples.

CHIP CORING

Benefits:

1. Minimum sample contamination.
2. Samples at 1-ft intervals.

Limitations:

1. Excessive number of trips.
2. Requires special service and equipment.

DOWN-HOLE POWER

(Rotary power on wire line)

Benefits:

1. Cheaper than conventional rotary (2-man crew).
2. Less fluid head on formation.
3. Recovery higher than cable tool.
4. Large-diameter cores.
5. Rotary method quickly adaptable to cable-tool well.

Limitations:

1. Requires special service and equipment.
2. Requires competent formations for anti-turn device on motor case.
3. Depth limitation.

3B: Drill-stem Testing

Benefits:

1. May help evaluate indicated fluid-bearing zones.
2. May obtain initial sample of formation fluids.
3. Initial bottom-hole pressure reading
4. May permit flow tests prior to running pipe.

Limitations:

1. Inherent hazard of sticking pipe.
2. Limited flow time in some formations.
3. Requires essentially gage hole (for packer seat).
4. Results often hard to evaluate.
   a. Inconclusive negative results.
   b. Contaminated flow.
   c. Questionable in low-pressure zones.
5. Safety hazards.

TIMING OF TESTS

AS PENETRATED

Benefits:

1. Better test likely.
   a. Less filtrate or mud-particle blocking.
   b. Packer seat more reliable (less filter cake; less loss of gage).
2. Shorter anchor.
   a. Less chance of kinking pipe.
   b. Better packer action.
3. Can use rat hole if necessary.
4. Less restricted packer selection.

Limitations:

1. Extra mud conditioning.
2. Delays operations.
3. Electric log may not be available.
4. Tends to increase number of tests.

AFTER FURTHER DRILLING

Benefits:

1. Reduced hole risk (less chance of junking hole—stuck tester in lower zone can be left).
2. Complete electric log available.
3. Minimum mud conditioning
4. Minimum operating delay.

Limitations:

1. Reduced chance for good test.
   a. More filter cake and filtrate.
   b. Poorer packer seats (may wash out).
2. Requires long anchors (may kink pipe; poorer packer action).
3. Can rat-hole test lower zone only.
4. Limited packer selection. Straddle packer required if:
   a. Lower zones flow.
   b. Danger of interzonal fluid loss.

TYPE TESTER

RAT-HOLE

Benefits:

1. Greater packer clearance on trips.
   a. Less packer damage.
   b. Less ram effect; reduces squeeze or swab.
2. Better packer seat; packer OD close to rat-hole ID
3. Cone-type packer can be used to seat in soft formation (no anchor).

Limitation:

1. Usable for near-bottom tests only

FULL-HOLE

Benefits:

1. More exposed hole area.
2. No reaming.
3. Less size limitation on usable tools.
4. Heavier, more rugged tester parts.

Limitation:

1. Sometimes harder to set packer.

3C: Instrument Logging

ELECTRIC AND ELECTRONIC LOGGING

Benefits:

1. Continuous data, entire bore hole
   a. Formation content
   b. Information on continuity of formation.
   c. Measurement control.
      (1) Depth of pay zones
      (2) Thickness of pay zones.
   d. Porosity and permeability.
   e. Geological correlation
2. Readily run any time.
   a. As hole is drilled
   b. After drilling.
3. Less hazardous to hole (than 3A or 3B).

Limitations:

1. Quantitative analysis limited
   a. Fluid content.
   b. Porosity.
   c. Permeability.
2. Sensitive to type drilling fluid.
3. Detailed analysis highly specialized.
4. Additional formation checks frequently required.
5. Mechanical problems above 350 F. in hole
6. Sensitive to bore-hole diameter

SELECTION OF TYPE OF LOGGING TOOL

	Electrical	Wall Micro-Resistivity A	Focused Beam Resistivity B	Detailed Focused Beam Resistivity C	Scratcher Resistivity	Gamma Ray	Induction	Neutron
Information:								
Fluid saturation	Yes	No	Yes	No	Yes	No	Yes	No
Porosity (percentage)	Yes	Yes	No	Yes	No	No	No	Yes
Permeability	Yes	Indication	Doubtful	Indication	No	No	No	No
Formation-water resistivity	Yes	No	No	No	No	No	No	No
Porosity (thickness of porous zones)	Yes	Yes	Yes	Yes	Yes	No	Yes[1]	Yes
Lithology changes	Yes	No	No	No	No	Yes[2]	No	No
Muds suitable:								
High-resistivity (fresh-water base or oil-emulsion[3])	Yes	Yes	No	No	No	Yes	Yes	Yes
Low-resistivity (high pH[4] salt-water base)	No	No	Yes	Yes	No	Yes	No	Yes
Oil, oil-base, empty hole	No	No	No	No	Yes	Yes	Yes	Yes
Cased hole	No	No	No	No	No	Yes	No	Yes

A Microlog or contact log.
B Laterolog or guard log.
C Microlaterolog

[1] In oil, oil-base mud, or empty hole only.
[2] Delineates shale from sandstone, limestone, dolomite, and coal
[3] Oil-emulsion muds with relatively low percent oil.
[4] pH 12 or higher.

MISCELLANEOUS INSTRUMENT LOGGING

CALIPER LOGS

(Open hole)

Benefits:

1. Bore-hole diameter and volume information.
   a. Aid in formation correlation (regional).
   b. Cementing operation data.
   c. Packer setting aid for drill-stem test.
   d. Check diameter effect on various types of logs.
   e. Evaluation of permeability-profile logs.
   f. Useful in gravel-pack and plug-back operations.
   g. Useful in casing-shoe location for recompletions.
   h. Locate parted casing.
   j. Underream checks.
   k. Shot-hole check, secondary recovery (old nitro-shot hole).

Limitation:

1. Gage limitations:
   a. Maximum about 36 in.
   b. Minimum about 4 in.

DIP LOGS

Benefits:

1. Useful in determing bore-hole dip and strike (at well tested).
   a. Helps define position in structure.
   b. Aids selecting location for nearby wells.
2. Bore-hole diameter information.
3. Aids formation correlation between wells.
4. Caliper information.
5. Study of bore-hole deviations (for other operations).
6. Very accurate sand-thickness data.
7. Useful in locating faults.
8. Continuous log

Limitations:

1. Not accurate for dips under 5 deg (unless substantiated by consistent low dip record in continuous profile).
2. Hole-size limitations.
   a. Dip contrast not good in small holes.
   b. Limits on maximum contacts in large holes.
3. Data normally not interpreted in field.

CALIPER TYPE

Specific Benefit:

1. Tool not sensitive to fluid in hole.

Specific Limitation:

1. Effective only in eroded formations.

RESISTIVITY TYPE

Specific Benefit:

1. Records in non-eroded holes.

Specific Limitations:

1. Requires conductive fluid.
2. Hole irregularities complicate electrical readings.

MUD LOGGING

(As aid in locating oil- and gas-bearing zones.)

COMPREHENSIVE SERVICE

Benefits:

1. Qualitative determination of gas in mud.
2. Continuous sample analysis.
   a. Lithology.
   b. Fluorescence and staining.
   c. Gas content.
   d. Visual porosity.
3. Core analysis.
   a. Porosity.
   b. Permeability.
4. Drilling time and data.
5. Mud characteristics.
   a. Weight.
   b. Viscosity.
   c. Chloride content.
6. Continuously attended.
7. All data correlated to depth.
8. Aid picking coring and drill-stem test points.
9. Usable in oil-emulsion muds.

Limitations:

1. Expensive service.[1]
2. Requires experienced personnel.
3. Qualitative data (limits benefits 1 and 2).
4. Difficulty locating true source of gas in mud (where upper sands may gas cut).

[1] Normally in use for extended period of time, principally in wildcat or exploratory wells.

LIMITED SERVICE

Benefits:

1. Less expensive.
2. Qualitative determination of gas in mud (continuous log, some types).
3. More portable—adapted to short service periods.
4. Continuous expert attendance not required (check by competent person needed periodically).
5. Some types provide data other than 2 above (rate of penetration, etc.).
6. Equipment may be leased or purchased.

Limitations:

1. Limited data (as compared to comprehensive).
2. Not directly correlated to depth.
3. Difficulty locating true source of gas in mud (where upper sands may gas cut).
4. Service more likely to be interrupted (irregular service attendance).

TEMPERATURE LOGGING

General Benefits:

1. Location of cement top behind casing
2. Location of lost-circulation zones.
3. Location of gas or fluid entry.
4. Useful for formation correlation (under some conditions).
5. Determination of formation temperature gradients and formation temperature
   a. Aids selecting cementing program.
   b. Aids selecting bottom-hole equipment and materials.
   c. Aids selecting mud program.
6. Location of fluid tops.

General Limitations:

1. Accurate cement-top determinations limited by:
   a. Time element.
   b. Requirement for fluid column to reach ambient temperature.
2. All other measurements subject to limitation 1-b.

MECHANICAL DEVICES

(Direct temperature recorders.)

Specific Benefits:

1. Inexpensive.
2. Adapted to rough usage.
3. Can be leased or bought.
4. Do not require conductor cables.

Specific Limitation:

1. Not sensitive to small temperature changes.

ELECTRICAL WIRE-LINE DEVICES

TEMPERATURE DIFFERENTIAL RECORDERS

Specific Benefit:

1. Measures small temperature differentials.

Specific Limitations:

1. Measures temperature differentials only.
2. Requires conductor cable and surface equipment.

DIRECT TEMPERATURE RECORDERS

Specific Benefits:

1. Measures small temperature anomolies.
2. Determines temperature gradients accurately.
3. Locates cement tops, fluid entry, etc.

Specific Limitation:

1. Requires conductor cable and surface equipment.

FIGURE 38-5. Formation evaluation methods.

HOLE SIZE

DRILLING
(To top of pay)

3 CORING TESTING LOGGING

4 DRILLING IN

4A Cable Tools

Benefits
1. Less harmful to mud-sensitive zones.
2. Permits incremental deepening (thin water-drive pays).
3. Lower per-day rig costs (extensive testing).
4. Effective in lost-circulation zones.
5. Permits casing swabbing.

Limitations:
1. Low-pressure formations.
2. Minor well pressures.
3. Well-control problems.

4B Rotary Tools

Benefits:
1. Well-pressure control.
2. Faster completion.
3. Better cores and core recovery.
4. Better electrical logs.
5. Greater flexibility of operations.

Limitations:
1. More likely to cause permeability damage (mud-particle or filtrate penetration).
2. Higher daily rig cost.
3. Possible loss of circulation.

Drilling-in Fluids

	Water-base Mud	Oil-emulsion Mud	Water: Fresh	Water: Salt	Oil-base Mud	Oil	Gas or Air
Availability	Readily available	Readily available	Readily available	Usually available	Reduced availability	Usually available	Available
Weight control	Excellent	Good	Poor	Poor	Fair	Poor	None
Cost	Cheap	Relatively cheap	Cheap	Cheap	Expensive	Relatively cheap*	Variable
Rig time	None extra	None extra	Some extra†	Some extra†	None extra	Some extra†	Extra†
Permeability damage	Yes	Yes	May water block	May water block	Reduced	Minimum	Minimum
Hazard	Not hazardous	Not hazardous	Not hazardous	Not hazardous	Inflammable	Inflammable	Gas hazardous
Crew rating	Reasonably clean	Unpleasant	Clean to handle	Clean to handle	Unpleasant	Unpleasant	Special handling
Effect on logging	‡	‡	‡	‡	‡	‡	‡
Sample interpretation	Acceptable	Difficult	Acceptable	Acceptable	Difficult	Very difficult	Difficult
Physical-property control	Good	Good	Poor	Poor	Fair	Poor	None

*It is assumed that if formation oil is used, any part lost to formation will be regained with well production, and remainder may be partially salvaged by cleaning and separating.
†In these cases the fluid named is assumed used for completing purposes only, requiring extra rig time for changing mud. Fluids not marked with † are assumed in use prior to drilling-in.
‡See Fig. 3, 3C: Selection of Type of Logging Tool—Muds Suitable.

5 STIMULATION

FIGURE 38-4. Drilling in.

⑤ CASING CEMENTING

Method

Conventional

Benefits:

1. Lower cost:
   a. service
   b. equipment
   c. rig time
2. Permits full use of scratchers.
3. Simplicity (minimizes operating hazards).
4. Faster completion.

Limitations:

1. Higher heads involved may damage pay zones.
2. Attempts to reach high annulus fill-up dangerous:
   a. possible formation break-down
   b. possible lost circulation
3. May be more critical in cement selection (setting time, viscosity maintenance, etc.).
4. May require more cement (in widely spaced cement zones).

Staged

Benefits:

1. Lower heads less likely to damage pay.
2. Saves cement in case of widely spaced zones.
3. Easier to obtain high annular fill-up.

Limitations:

1. High cost.
2. Slower completion.
3. More operational hazards.
4. Limits use of scratchers.
5. Possible leaks in stage collars:
   a. from corrosion
   b. from mechanical failure

Selection of Cement

	MANUFACTURED CEMENTS					ADDITIVES				
Characteristics	Portland (ASTM Type 1)	High Early-strength (ASTM Type III)	Slow-set (Not ASTM)	Sulfate-resistant	Low Water-loss*	Effect On	Bentonite	Expanded Perlite	Pozzolan	Set Retarders†
Availability:	Universal	Limited	General	Limited	Limited		....	....	....	....
Depth rating (pumpability):	Limited	Very limited	Good	Limited	Limited	Pumpability:	Reduces	No effect	Reduces slow-set. No effect on Portland	Increase
WOC time:	Normal	Reduced	Normal	Normal	Normal		....	....	....	....
Recommended weight range, lb per gal:	15.0—15.5	14.0—15.0	15.5—16.5	14.0—16.0	14.0—14.5	Weight (density):	Reduces	Reduces	Reduces	No effect
Perforating characteristics:	Normal	Normal	Normal	Normal	Normal	Perforating characteristics:	Improves	Improves	Improves	No effect
Water loss:	High	High	High	High	Low	Water loss:	Decreases	No effect	No effect	Decrease
Sulfate resistance:	Fair	Fair	Good	Excellent	Fair	Sulfate resistance:	Reduces	Reduces	Improves	No effect
Additive compatability:	Excellent	Fair	Poor	Poor	Poor		....	....	....	....

*Contains polyvinyl alcohol, etc.
†Calcium lignosulfonates, etc.

Equipment To Be Considered

Wall Cleaners (Scratchers, etc.) — **Centralizers** — **Cementing Heads** — **Cementing Plugs** — **Floating Equipment** — **Stage Equipment**

(In view of highly varied design, adaptability ratings of this equipment requires mechanical-engineering analysis beyond the scope of this committee.)

FIGURE 38-5. Casing cementing.

⑥ CASING PERFORATING

Method

Jet

Maximum penetration.
Minimum cement shattering.
Minimum burring.
Multiple strings (no deflection).
Angle shooting possible.
Expendable guns available.
Adaptable to permanent-type well completions.
Minimum junk left in bore hole.
Can perforate longer section in single run.

Bullet

Selective firing advantage.
Cost advantage.
Large uniform hole diameter.

Optimum Density of Perforations

Porosity and permeability (vertical vs. horizontal).
Frangibility of formation.
Casing size (perforation area vs. bore-hole area).
Cost consideration.
Past field performance.
Size of individual perforations.

Portion of Pay Zone Perforated

Water level.
Gas-cap level
(consider degree of vertical permeability and pressure drawdown while producing).
Amount of section necessary:
1. Initial top allowable.
2. Highest ultimate recovery (distribution of withdrawal).

Perforating Fluid

	Water-base Mud	Oil-emulsion Mud	Water: Fresh	Water: Salt	Oil-base Mud	Oil	Gas or Air
Availability	Readily available	Readily available	Readily available	Usually available	Reduced availability	Usually available	Available
Weight control	Excellent	Good	Poor	Poor	Fair	Poor	None
Cost	Cheap	Relatively cheap	Cheap	Cheap	Expensive	Relatively cheap*	Variable
Rig time	None extra	None extra	Some extra†	Some extra†	None extra	Some extra†	Extra†
Permeability damage	Yes	Yes	May water block	May water block	Reduced	Minimum	Minimum
Hazard	Not hazardous	Not hazardous	Not hazardous	Not hazardous	Inflammable	Inflammable	Gas hazardous
Crew rating	Reasonably clean	Unpleasant	Clean to handle	Clean to handle	Unpleasant	Unpleasant	Special handling
Physical-property control	Good	Good	Poor	Poor	Fair	Poor	None

*It is assumed that if formation oil is used, any part lost to formation will be regained with well production, and remainder may be partially salvaged by cleaning and separating.

†In these cases the fluid named is assumed used for completing purposes only, requiring extra rig time for changing mud. Fluids not marked with † are assumed in use prior to drilling-in.

FIGURE 38-6. Casing perforating.

⑦ FLOW TESTING

Desired Information (initial evaluation of reservoir and well completion).

1. Fluid Production Data
   a. Volume
      (1) Oil
      (2) Water
      (3) Gas
      (4) Sand
   b. Physical characteristics (gravity, pour point, etc.)
   c. Surface pressures
2. Bottom-hole Samples
3. Bottom-hole Temperatures and Pressures
4. Pressure-buildup Tests (for further information on this method of flow testing refer to part 2 herein)

FLOW TESTING

FIGURE 38-7. Flow testing.

⑧ STIMULATION

Large-area Penetrators

Nitro-shooting

Benefits:

1. Bore-hole enlargement combined with fracturing.
2. Not selective to single fracture at weakest bedding plane.
3. No hydrostatic or fluid effect on permeability.
4. Stimulant itself relatively inexpensive.

Limitations:

1. Cleanout problems and expense.
2. Hazard to personnel, well, equipment.
3. Limited to open-hole completions.

Acidizing

Benefits:

1. Moderate bore-hole enlargement.
2. Primarily adapted to formations of appreciable calcareous content (not generally adaptable to sandstone).
3. Cleans out, enlarges, interconnects fractures, vugs, other channels.
4. Stimulant relatively inexpensive.
5. Adaptable to both open-hole and set-through completions.

Limitations:

1. May require residue cleanout.
2. Somewhat hazardous and corrosive.

Hydraulic Fracturing

Benefits:

1. No bore-hole enlargement.
2. Highly flexible procedure:
   a. Permits multiple or single fracture.
   b. Can combine advantages of fracturing and acidizing.
   c. Wide latitude of sand-carrier agent.
3. Maximum effective area of stimulation.
4. Maximum extension of inherent or induced fractures.
5. Propping agent maintains high permeability.
6. Permits relatively localized fracture level if desired (in approximately horizontal bedding planes).
7. Adapted to either open-hole or set-through completions.

Limitations:

1. May involve cleanout of propping sand.
2. Somewhat hazardous with some carriers.
3. Relatively expensive.
4. High pressures may damage tubing or casing.
5. Intricate down-hole operations requiring packer manipulations.

Skin Breakers

Gun Shooting (Open Hole)

Benefits:

1. Improves permeability adjacent to bore hole* blocked by: *a*, mud solids; *b*, mud filtrates; *c*, emulsions; *d*, formation-clay swelling.
2. Relatively inexpensive.
3. Minimum cleanout required.
4. Highly selective (location).
5. Fracture starting at given level (if followed by hydraulic fracturing).

Limitations:

1. Limited penetration.
2. Ineffective in large bore holes.

Mud Acid

Benefits:

1. Improves permeability adjacent to bore hole blocked by: *a*, mud solids; *b*, mud filtrates; *c*, emulsions; *d*, formation-clay swelling.
2. Limited benefits from usual acidizing effects.

Limitations:

1. May require residue cleanout.
2. Somewhat hazardous and corrosive.
3. More expensive than usual acidizing.
4. Limited selectivity to level.

Surface-active Agents (Fluid Squeezes)

Benefits:

1. Improves permeability adjacent to bore hole blocked by: *a*, emulsions; *b*, mud filtrates.
2. In certain combinations with other agents may remove clay-particle blocks.
3. May reduce breakdown pressure for hydraulic fracturing.

Limitations:

1. Relatively expensive (some commercial types).
2. Sensitive to chemistry of formation and fluids.
3. May require residue cleanout.
4. Limited selectivity to level.

Jet Acidization

Benefits:

1. Especially adapted to remove thin sand-face deposits (not soluble by usual methods).
2. Minor cleanout required.
3. Limits bore-hole enlargement (where not needed).
4. Suitable for recurring treatment.
5. Highly selective (location).

Limitations:

1. Low penetration.
2. Comparatively expensive.

Marble Shooting

Benefits:

1. Especially adapted to remove thin sand-face deposits (not soluble).
2. Minor cleanout required.
3. Limits bore-hole enlargement (where not needed).
4. Suitable for recurring treatments.

Limitation:

1. Least penetration of listed stimulants.

*If penetration sufficient.

FIGURE 38-8. Stimulation considerations.

9 PLUGBACK

Drill Pipe—Tubing

Benefits:

1. Avoids excess contamination of plugging material.
2. Less expensive when placing long plugs.

Limitations:

1. Ineffective for placing small plugs.
2. Requires pumping equipment.

Explosive-type Squeeze Tool (Wire-line)

Benefits:

1. Effective for placing small plugs.
2. Does not require pumping equipment.
3. Greater placement accuracy.

Limitations:

1. Expensive per unit volume placed.
2. Wire-line operation—fishing hazard.
3. Requires cased or gage hole.

Bailer

Benefits:

1. Effective for placing small plugs.
2. Does not require pumping equipment.

Limitations:

1. Expensive when placing long plugs.
2. Danger of contamination of plugging material.
3. Not adapted to use of plugging material of less density than well-bore fluid.
4. Depth.

Plastic

Benefits:

1. Good seal with formation.
2. Short setting time.
3. Insoluble in brine when set (phenolformaldehyde).

Limitations:

1. Expensive.
2. Generally cannot be used with drilling mud in hole.
3. Sensitive to contamination.
4. Bore-hole temperature restrictions.
5. Unpredictable characteristics.

Cement

Benefits:

1. Inexpensive.
2. Can be used with drilling mud in hole.
3. Relatively insensitive to contamination.
4. Greater strength.

Limitation:

1. Longer setting time.

Gypsum Cement

Benefits:

1. Short setting time.
2. Inexpensive.
3. Can be used with drilling mud in hole.

Limitations:

1. Temporary plug (subject to deterioration with time and fluid exposure).
2. Time restriction on placement.

FIGURE 38-9. Plugback.

⑩ SQUEEZE CEMENTING

Conventional

Benefits:

1. Technique well known to industry.
2. Can be used in well killed with drilling mud.
3. Flexibility.

Limitations:

1. Multiple stages frequently necessary.
2. Requires high pressures.
3. Requires the use of a packer.
4. May squeeze off portion of oil zone.
5. Requires a rig to drill plug.

Low Water-loss and Lost-circulation Material

Benefits:

1. Usually seals in one stage.
2. Can be used in wells killed with drilling mud.
3. Flexibility in control of necessary cement volume.

Limitations:

1. Industry not familiar with process.
2. May squeeze off portion of oil zone.
3. Requires high pressures.
4. Requires the use of a packer.
5. Requires a rig to drill plug.
6. High cost per unit volume.

Low-pressure*

Benefits:

1. Good results obtainable at low pressures.
2. Seldom requires a packer.
3. Does not require a rig to drill plug.
4. Inexpensive.
5. May be easier to regain oil production.
6. Usually requires less cement and/or stages.

Limitations:

1. Industry not familiar with process.
2. Less suitable for tight fractured formations.
3. Should not be used in well killed with drilling mud.
4. Requires measurement of slurry volume.

*Generally used in connection with permanent-type well completions.

Diesel-oil Cement

Benefits:

1. Increased pumpability.
2. Usually requires less cement and/or stages.
3. Less likely to damage oil-producing zone.
4. Inherently more selective in shutting off water.
5. Can be used in well killed with drilling mud.

Limitations:

1. Usually requires use of a packer.
2. Principally applicable to water shutoff; not recommended for gas-oil ratio control.
3. Intimate contact with water in formation required for successful application.
4. Frequently requires rig to drill plug.

Explosive-type Squeeze Tool (Wire-line)

Benefits:

1. Faster placement for small amount of cement.
2. Greater placement accuracy.
3. Very rapid set of cement provides seal with minimum volume.

Limitations:

1. Expensive per unit volume placed.
2. Wire-line operation—fishing hazard.
3. Requires cased or gage hole.

Bradenhead Squeeze

Benefits:

1. Simplicity.
2. Inexpensive.
3. Usually does not require rig.
4. Can be used in well killed with drilling mud.
5. Does not require a packer.

Limitations:

1. Pressure limited to safe casing capacity.
2. May involve drilling excessive amount of cement (because of pressure limitations).
3. Mainly applicable to shallow wells.

FIGURE 38-10. Squeeze cementing.

(11) COMPLETION EQUIPMENT

Bottom Hole

Artificial Lift

Rod Pumps

Benefits:
1. Simple design.
2. Pump with high or low fluid level.
3. Not readily gas locked.
4. Use in corrosive wells.
5. Use in sandy wells.

Limitations:
1. Needs unit to service.
2. Volume—depth limitations.
3. Crooked holes.
4. Paraffin deposition.

Insert Pumps

Benefits:
1. Pump can be pulled without pulling tubing.
2. Minimum bore obtainable (to obtain maximum displacement efficiency).
3. Allows for more versatile design (traveling barrel, top holddown, etc.).

Limitations:
1. Minimum to medium volume capacity.

Tubing Pumps

Benefits:
1. Maximum volume for a given tubing size.
2. Heavier-barrel walls can be used.

Limitations:
1. Tubing must be pulled to service pump.
2. Traveling-plunger type only.
3. Minimum bore (1¾-in.) cannot be used at maximum sucker-rod depth.

Casing Pumps

Benefits:
1. Large volume.
2. No tubing needed.
3. Pump can be pulled on rods.

Limitations:
1. Depth (difficult to unseat).
2. Requires relatively high fluid.
3. May overload rods.
4. Possible casing wear.

Hydraulic Pumps

Benefits:
1. Can be pulled without a servicing unit (hydraulic pump out).
2. High volume.
3. High volume at greater depth.
4. Runs in crooked hole.
5. Minimum paraffin trouble.

Limitations:
1. Complex design.
2. Requires two tubing strings.
3. Severe shock encountered with gas in solution in fluid.
4. Clean power oil imperative.

Electro-centrifugal Pumps

Benefits:
1. High volume.
2. Runs in crooked hole.
3. Will not gas lock.
4. Use in corrosive wells.
5. Use in sandy wells
6. Paraffin causes no trouble.

Limitations:
1. Complex design.
2. Requires electric cable secured to tubing.
3. Needs unit to service.
4. Needs high fluid level.
5. Effect of high temperature and pressure on insulation (great depth).

Gas

Benefits:
1. Runs in crooked holes
2. Will not gas lock.
3. Operates with high or low fluid level.
4. Operates at any depth.
5. Simple overall design.

Limitations:
1. Needs unit to service (except for wire-line valves).
2. Requires internal or external gas supply under pressure
3. Volume.
4. May waste gas.

Stationary Valve (Intermittent or continuous)

Benefit:
1. Selective to high or low fluid volume.

Limitations:
1. Sensitive to paraffin.
2. Stage operation may be required for depth.
3. Valve-operating troubles.

Plunger or Ball

Benefits:
1. Adaptable to heading or weak wells.
2. Can utilize well's own gas.
3. Will handle limited water volume without emulsifying.
4. Not sensitive to paraffin.

Limitations:
1. Volume limitations.
2. Tubing drift requirements.
3. Cycling time vs. volume.

Flowing

Refer to Fig. 2.

Surface Equipment

Artificial Lift

Rod Pump
- Hydraulic Long Stroke
- Beam Unit
- Pneumatic Unit

(Comparative adaptability of above surface equipment requires mechanical engineering analysis beyond scope of this committee.)

Hydraulic Power Unit

Electro-centrifugal

Gas-lift Controls

Flowing

Christmas tree and well heads (see API Std 6E for pressure classifications)

Casing Suspension

	Threaded Hangers	Slip and Packing Hangers	Welded Hangers	Slip and Welded Hangers
Well depth	Moderate	Deep	Shallow	Deep
Tension adjustment	None	Good	None	Good
Casing	Any grade	Any grade	Low carbon*	Low carbon*
Seal before removing preventers	Possible†	Possible‡	Not feasible	Not feasible

*High carbon casing weldable with proper preheat technique. See API Std 6E—Appendix.

†By attachment to last joint to lower through preventers.

‡Automatic type only.

Tubing Suspension

	Threaded Hangers	Sliding-seal Hangers
Well depth	All	All
Packer setting		
a. Normal	Usable	Good
b. Under pressure	Not suitable	Good

Special application (twin tubing, etc.).

FIGURE 38-11. Completion equipment.

⑫ MULTIPLE-ZONE COMPLETIONS†

Benefits:

1. Reduces initial drilling and development costs.
2. Permits development of:
   a. Multiple marginal zones.
   b. Marginal with good zones.
3. May eliminate drilling forced offset well.
4. Provides earlier development of multiple horizons.
5. Economics improve with increasing depth and cost.

Limitations:

1. Must size oil strings for probable ultimate depletion equipment.
2. Complicates:
   a. Workover.
   b. Well testing (bottom-hole pressures, flow tests, etc.).
   c. Inhibition measures (corrosion, paraffin, etc.).
   d. Formation stimulation.
   e. Artificial lift.
3. Requires specialized equipment, operations, personnel training, and service.
4. Increases danger of junking hole (e.g., sand problem).
5. Increases loss of production during remedial operations (one zone down shuts in other).
6. Higher workover down time.
7. May permit excessive drainage to offset.
8. Uncertainty of continuous zone segregation—possible resultant reservoir damage.
9. High operating costs.
10. Some states prohibit multi-zone completions.

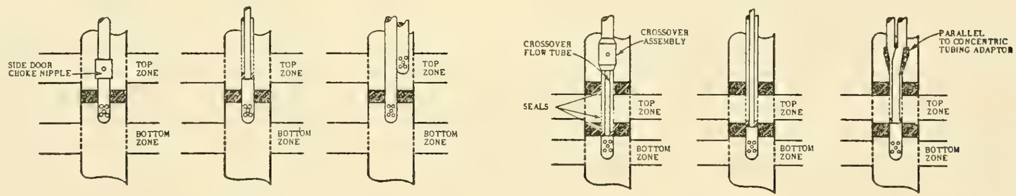
Number of Zones

Dual-zone Production
Choice of Settings

Single Packer: Single Tubing String; Dual Concentric Tubing String; Dual Parallel Tubing Strings

Dual Packer: Single Tubing String; Dual Concentric Tubing String; Dual Parallel Tubing Strings

Triple- or Quadruple-zone Production
Choice of Settings
(Stage of development not adequate for committee action.)



Rating:	Single Packer – Single Tubing String	Single Packer – Dual Concentric Tubing String	Single Packer – Dual Parallel Tubing Strings	Dual Packer – Single Tubing String	Dual Packer – Dual Concentric Tubing String	Dual Packer – Dual Parallel Tubing Strings
1. Cost (initial).	A	C	E	B	D	F
2. Operational flexibility and cost:						
a. Well repair (pulling, etc.).	A	C	E	B	D	F
b. Stimulation operations:						
1. Swabbing.	Both Zones*	Both Zones	Both Zones*	Both Zones*	Both Zones	Both Zones
2. Acidizing.	B	B	B	A*	A	A
3. Hydrafrac.	A	C	E	B	D	F
c. Testing (pressure bombs, etc.).	B*	No	A	B*	No	A
d. Paraffin control (mechanical).	Tubing Only	Inner Tubing Only	Both	Tubing Only	Inner Tubing Only	Both
e. Crossover.	No	No	No	Yes	No	No
3. Casing protection:						
a. Dead fluid column.	No	No	No	No	Yes	Yes
b. Inhibitor.	No	Casing & Outer Tubing Only	Casing & Upper Tubing Only	No	Casing Only	Casing Only
Adaptability: (Considering all above factors)						
• Two flowing zones.	Good	Good	Best	Good	Good	Good
• Top flowing—bottom artificial lift.	Good	Fair	Best	Good	Fair	Good
• Top artificial lift—bottom flowing.	Not Adaptable	Difficult	Best	Good	Fair	Good
• Two artificial lift.	Not Adaptable	Difficult	Best	Fairly Good	Fair	Good

NOTE: Alphabetically classed in order of preference.
*Requires use of wire-line tool to set side door or crossover.

†Acknowledgment to Marshall C. Turner, Paper No. 851-28-H: Dual-completion Equipment and Practices, presented at the meeting of the Mid-Continent District, API Division of Production, March 1954.

FIGURE 38-12. Multiple-zone completions.

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Part Seven

SUBSURFACE REPORTS

Chapter 39

WRITING SCIENTIFIC REPORTS

George W. Johnson

Unfortunately it is impossible to be very specific in a discussion of such a broad subject as writing scientific reports, for what may be said specifically about one scientific report may not apply to another. It may be said of reports in general that they increase in number and importance from year to year. If one needs assurance on this point, he need only examine current issues of scientific journals, hardly one of which does not have an article on the need for improvement of reports and what should be done to solve this problem. Research organizations and institutions, whose chief products are reports, spend increasing sums each year to insure that the products not only convey the information intended but reflect credit upon the organizations from which they originate.

What makes a report good? Before answering such a question, one should consider what a report is. A report may be defined as a presentation of material that is organized to meet the purpose for which the material is to be used. A good report, therefore, must fulfill a specific purpose, and its organization and presentation must serve this purpose as adequately and as efficiently as possible.

Because the number of purposes of reports almost equals that of reports, a discussion of the general subject of report writing gravitates inevitably to a discussion of reports in particular subject areas and to specific report situations. So it is with this brief discussion, which will consider report writing in the general field of the earth sciences and which will offer some specific examples that may serve as a guide rather than as a pattern in report organization, documentation, and style.

ORGANIZATION

Organization of a report is logical arrangement and connection of the parts to fit the purpose of the report. Since the report is the result of a study, it follows that a purpose must guide the planning of the means and methods by which data are collected, must determine the organization of the material collected, and must give focus to the writing of the report itself.

The formulation of a statement of purpose should therefore be a first step in any study leading to a report, even though such a statement may require some modification as the study progresses. Definition and constant review of purpose serve to orient and to maintain proper perspective for a writer who otherwise might become lost in a maze of detail.

If a study is extensive and detailed, it is advisable to formulate an outline of procedure. A sample outline of procedure follows:

Outline for Petroleum Reconnaissance Study

Regional reconnaissance exploratory geology requires both extensive ground and air coverage. To evaluate a large region for its petroleum possibilities, one should consider the following points:

I. Delineate areas of sedimentary and basement complexes and areas of maximum and minimum section thickness. The relationship of these features should be accurately established and delineated on maps.

II. Establish the structural fabric (folds, faults) of the area (prepare maps and cross sections).

To evaluate properly the structural fabric of a region, define the broad tectonic elements and their relationships. During this evaluation procedure, the following questions should be considered:

A. Is the area structurally complex or simple?
B. What are the trends and the distribution of the major and minor structural elements?
C. How do the structural elements change in space (magnitude, direction)?
D. What are the relative sizes and the relationships of the various structural features?
E. What is the structural history of the area (date of folding and faulting and periods and extent of erosion)?
F. What relationship exists between the structural and sedimentary pattern, and is this relationship favorable for accumulation of petroleum?

III. Determine the major stratigraphic units of the section, and attempt to evaluate the significant lateral, lithologic, paleontologic, and thickness changes exhibited by these units. Systematic procedures for stratigraphic analyses are required.

IV. Define unconformities (extent, type, relationship).

V. Check carefully for possible source and reservoir rocks and entrapment conditions.

A. *Source Rock*

1. What rock types would probably be most favorable, and what percentage of these types are represented in the total section?
2. What are the sedimentational and structural relationships between possible source strata, reservoir strata, and entrapment conditions?
3. Is permeability sufficient to permit migration from the source type to associated porous types?
4. What are the thickness, lithologic variation, and distribution?
5. What is the percentage of organic material, and how is it distributed?
6. Under what environments were the strata developed?

B. *Reservoir Rock*

1. What are the favorable types (sandstone, fractured or porous carbonate, fractured shale, argillaceous sands)?
2. What relationships exist between reservoir rock and structure?
3. Could the strata qualify for a possible source as well as for a reservoir?
4. What about thickness, extent, porosity, and permeable variability?
5. What are the relationships to erosional surfaces, and what is the relationship of time of origin and migration to these erosional surfaces?
6. Are the strata in reach of economic drilling?
7. What about A.P.I. gravity variations?

C. *Entrapment Conditions*

1. Are the trap conditions controlled by sedimentational or structural irregularities or both? To what extent?
2. What are the relationships between the trap feature, source rock, and reservoir rock?
3. What are the extent, pattern, and trend of the trap?

VI. Describe the geological history of the area.

A. *Sedimentational History*

To decipher the sedimentational history of an area, one should consider the following points:

1. Period and extent of oscillations.
2. Environmental conditions prevalent during various oscillatory stages.
3. Sedimentational patterns developed during the oscillation periods.
4. Source direction of sediments.
5. Post-depositional changes.
6. Relation of sedimentary patterns to tectonic adjustments.

B. *Structural History*

1. What effect did structural adjustment during sedimentation have on development of the stratigraphic pattern (faulting, local and regional warping and arching, tilting)?
2. When did the major periods of folding and erosion occur? What about the degree and variation in tectonism?

A clear picture should be formed of erosional intervals and chances of survival of the oil, and one should bear in mind the deformation of strata, degree of erosion, and subsequent blanketing by impervious rock.

Regional reconnaissance geological investigations demand accurate and multiple field observations and an ability to place these data in their proper category prior to final analysis.

When material has been collected, one faces the problem of organizing it for a report. It is of utmost importance that this problem be solved properly before actual writing is begun. Writing before an acceptable outline is decided upon is actually a waste of time.

When one first considers the problem of organization, he may be so imbued with his study that he uses the plan followed in gathering the material to formulate the structure of his report. In other words, the first impulse might be merely to push the material together in much the same order in which it was collected. The result would be a routine account of what was done, a kind of research diary, in which the reader could find the purpose and results of the study only by diligent search. Such an organization, although it may serve its purpose well in guiding a study, is certainly not to be recommended for a report, because it is not adjusted to the needs of those who will read the report.

How should one proceed? Because a new and fresh view of the material and the purpose of the study is called for at this point, one would do well to consult with an intelligent person who is unacquainted with the particular study. One should discuss with such a person why the study was undertaken, how it was conducted, what the results were, and how the report is to be used. Such discussion helps to bring the problem of organizing the report into proper focus, because one is forced in his explanations to do essentially, in an informal way, what he must do in the report—answer first questions first.

The first step in organizing a report consists of dividing the material into general classifications that are suited to and arranged for the convenience of those who are to read the report. Then the subdivisions of each general classification should also be made consistent with this purpose, so that the structure of the whole report helps to bring the material into sharp focus for the reader.

In checking an outline one should examine the main headings, together with each series of subheadings, to make sure that (1) the terminology of each is accurate, (2) the main headings and each series of subheadings are properly proportioned and in parallel form, and (3) there is no single subdivision of a topic (each heading represents a division of material; therefore, because no thing can be divided into one part, a single subdivision is obviously illogical).

At this point, it might be advisable for the report writer to discuss again his whole report problem with someone unacquainted with the study, this time in terms of the outline as set up. Such a discussion, which should essentially be an explanation of how the outline achieves its purpose, often clarifies and develops a point that was only partially realized. Although it is true that any outline, no matter how carefully made, requires some modification during actual writing, failure to perfect the organization as much as possible before writing is begun results in much waste of time. In other words, the more one clarifies and crystallizes his concept of what the report should be, the more efficient and productive will be his efforts in writing the report.

An outline is used in a report as a table of contents, which serves, together with headings and transitional elements in the text, to keep the reader oriented as

PROCESSING THE PLATE

The dichromated albumen process is the standard method of preparing zinc lithographic plates. All other plate-making processes for zinc are modifications of this one, which is herein discussed under the headings

Treatment of the Image

Treatment of the Non-Image

Treatment of the Image

The treatment of the image involves three steps: cleaning, sensitizing, and arcing (Sayre, 1939, p. 50).

Cleaning: Because zinc is readily oxidized upon contact with air, a zinc plate must first be covered with a layer of zinc oxide. Dilute hydrochloric acid, which reacts with the oxide but not with the pure zinc, is used to remove the oxide. Soluble zinc chloride, the product of the reaction, may be washed off the plate with water.

Sensitizing and Arcing: The sensitizer, a light-sensitive solution of ammonium dichromate and albumen, is spread in a smooth, uniformly thin layer over the plate and allowed to dry. The plate

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FIGURE 39-1. Sample report page illustrating a format for three levels of headings.

he examines a report. Nelson (1952, p. 23-34) has made an excellent study of this important point.

Too frequently a report does not have text between some of the headings. For instance, a section is sometimes introduced only by a series of headings arranged in descending order, the text in that section beginning with a minor topic. Such a lack of introductory and explanatory material is to be disparaged because the reader is given no general orientation to, or concept of, the subject that the text in that particular section should provide.

It is essential that the relative importance of headings as listed in the table of contents be indicated clearly in the text by positioning on the page and by capitalizing and underlining in a typed manuscript. Figure 39-1 illustrates a a format for three levels of headings. Four levels of headings are usually arranged so that the first- and second-order headings are centered on the page, while the third- and fourth-order headings have the same format as those at the left margin in Figure 39-1. Five levels of headings may be provided by placing the first two in the center of the page and the third, fourth, and fifth at the left margin. However, use of more than four levels of headings raises the problem of offering the reader sufficient typographic contrast, a problem that may be solved by the use of a numbering system such as that described by Ulman (1952, p. 149-152).

The following sample outlines of reports are from the files of several major oil companies.

OUTLINE FOR GEOLOGICAL REPORT

I. *Title*

The title of the report should be brief but specifically descriptive. Two thirds of a report on "The Mesozoic Stratigraphy of Alaska" should not be devoted to economic geology.

II. *Abstract*

The abstract, which should be prepared from the final draft of the report, should contain only the essentials of the problem and should include general information on area location, stratigraphy, structure, correlation, and economic products. The abstract should encourage the reader to read the report.

III. *Acknowledgments*

One should acknowledge all those who have given assistance during preparation of the report (identifying fossils, classifying rocks, photographing specimens, checking field and laboratory data, criticizing manuscript, drafting, surveying, etc.). Recognition whenever and wherever it is due adds to the value of the report.

IV. *Introduction*

The introduction of any report must be organized and presented to give the reader proper orientation to the text. Such topics as location and size of area investigated, purpose and method of investigation, and previous geologic studies of the area should be treated. The subject material included under this heading will, of course, vary with the type of problem involved and the purpose of the report.

V. *Geography and Geomorphology*

Under this heading the following topics should be considered: relief features, relation of relief to stratigraphy and structure, drainage patterns and characteristics, general rock distribution and exposure, vegetational pattern, and culture.

VI. *Geology*

A. *Stratigraphy*

1. *Sedimentary rocks*

a. General discussion of stratigraphic sequence. Include graphic section or tabulated section. The former is preferred.

b. Regional and local stratigraphic relationships.

c. Detailed discussion of each formational unit. (Each formation should be photographed and the photograph properly captioned and integrated into the text.)

Location of typical exposure or exposures.
History.
Thickness (maximum and minimum).
Lithology (may involve a detailed graphic section).
Stratigraphic relationships.
Paleontology and age.
Environment of deposition.
Correlation.

2. *Igneous rocks*

Discussion should include types, distribution, relationships, and age.

3. *Metamorphic rocks*

This discussion should also include types, distribution, relationships, and age.

B. *Structure*

1. Regional and local trends and relationships.
2. Relation of structure to physiography.
3. Folding (intensity, type, age, closure, trend, economics).
4. Faulting (intensity, type, age, economics, trend, pattern).

VII. *Economic products*

VIII. *Conclusions and recommendations*

Statements relating to conclusions reached and recommendations presented should be clear and concise. In economic work this section may be the only one in which management finds an interest and may, therefore, precede the body of the report.

IX. *Bibliography*

OUTLINE FOR REPORT ON EXPLORATORY (WILDCAT) WELL

I. *Introduction*

Name of well and company, location of well, elevation (derrick floor and ground), date commenced, date of completion or abandonment, date of final depth, casing record (perforated intervals, size, cement data), total depth, type of drilling equipment, summary of well history (hole deviation, coring program, logging surveys, mechanical difficulties, etc.).

II. *Purpose of drilling well*

III. *Summary*

1. Age, thickness (with corresponding depths), relationships, and lithologic summary of formations.
2. Statement on the regional and local structure.
3. Comments on oil and gas shows; age of host sediment.

IV. *Conclusions and recommendations*

V. *Geology*

1. Stratigraphy (general statement).
   a. Regional: variation in facies, thickness, unconformities, etc.
   b. Local: (based primarily on penetrated section); relationship to regional stratigraphy; paleontologic and mineralogic summary (contributed by stratigraphic laboratory).
2. Structure (general statement).
   a. Regional: discussion of broad structural grain (fault and fold pattern).
   b. Local: areal geologic map, structure map, cross sections; description of local structure and its relationship to the regional structural fabric.

VI. *Discussion of logging data (electric, radioactive, thermal, drill time, core analysis, etc.).*

VII. *Accompanying enclosures*

1. Index map (local and regional).
2. Geologic, structural, isopachous, and lithofacies maps.
3. Local and regional cross sections.
4. Well log (lithic and electric, showing cored intervals, casing points, tested intervals, etc.).
5. Chronologic chart.
6. Correlation chart.
7. Photographs.

VIII. *Miscellaneous data (summary)*

1. Mud variations (salinity, viscosity, and temperature).
2. Condition of hole (caving, deviation).
3. Bottom-hole pressures.
4. Gas recording.
5. Bit, core, and casing problems.
6. Formation tests.
7. Perforation program.

IX. *Detailed description of ditch and core samples*

Interval (ft.)	*Description*
2110—25	Coarse, gray, unconsolidated sand.
2125—35	Red, slightly mottled claystone.
	————Top Cramer formation (Oligocene)————
2135—90	Medium-grained friable sandstone with 10 percent red claystone.
2190—2210	(Core 1) (15 feet recovered). Dark-gray shale with thin streaks of fine-grained, slightly oil-stained sandstone (medium acetone cut, strong fluorescence); shows few high-angled fracture planes with faint striations at 60° to the axis of core; average dip about 16°; locally 12° and 22°; hole deviation 2° off vertical.

OUTLINE FOR REPORT ON PETROLIFEROUS PROVINCE

I. *Introduction*

1. Importance today and in earlier history.
2. Location and boundaries. Illustrate with map showing location of productive areas and names of more important fields. Give states involved and relative importance of each.
3. Subprovinces if any.
4. Date of discovery and history of development. Most active areas at present.
5. Unusual characteristics in the geology and in the occurrence of oil and gas.
6. Surface indications of oil and gas.

II. *Geomorphology and general geology*

General statement regarding physiography, range in age of rocks, thickness of strata, regional and local structure and their influence on topography, igneous activity, extent of exposures, explanation of techniques best adapted to area.

III. *Stratigraphy*

1. Thickness, character, age, and distribution of the rocks.
2. Stratigraphic table or, preferably, columnar section or sections.
3. Description of surface and subsurface formations by systems. Correlation chart.
4. Lateral variations in thickness and character (facies changes), sources of sediments, shifting of axis of geosyncline of deposition, old shore lines.
5. Unconformities, wedge areas, overlap and offlap relations, buried topographic features, etc.
6. Key horizons.
7. Methods of subsurface correlation.
8. Producing horizons, continuity, lithologic character.

IV. *Structure*

1. Description of surface and subsurface regional structure and relation to other major tectonic features, rate of dip, age and origin, etc. (use structure contour map or maps and cross sections).
2. Influence on distribution of formations.
3. Modifying structural features (including faults and buried hills and ridges); nature, size, and amount of closure (if any); and trends.
4. Changes in structure with depth, times of subsidiary folding and faulting, and modification of earlier structures by later deformation. Isopach maps.
5. Brief statement regarding relation of production to regional and local structures.

V. *Paleogeology*

1. Geologic history of area. Influence on sedimentation. Evolution of present structure. Subsurface areal and structure maps below unconformities contrasted with surface-geology maps.
2. Times of igneous activity. Types and distribution of intrusion and extrusion.
3. Degree of metamorphism of various horizons.

VI. *Occurrence of oil and gas (if several subprovinces, consider each separately)*

1. Types of traps. Describe each and illustrate by producing fields. Relative importance of each. Relations to structure.
2. Methods of prospecting.
3. Barren structures and possible reasons therefor.

4. Reservoir horizons. Number, age, relative importance, character, thickness, continuity, porosity, permeability, kinds of cement, thickness, and degree of saturation of each and amount and character of occluded water present.
5. Water horizons.
6. Reservoir pressures.
7. Composition of edge water.
8. Possible sources of oil and gas and probable time or times of accumulation.
9. Possibility of extending producing areas or discovering new producing horizons. Indicate most promising areas and ages of prospective horizons.

VII. *Description of several typical pools, illustrating each important mode of occurrence*
1. Location, date of discovery, exploration methods employed, etc.
2. Geography and physiography.
3. Surface and subsurface geology. Contour maps and cross sections.
4. Type of trap.
5. Producing horizons. Character, extent, and depths of each.
6. Grade of oil.
7. Methods of drilling.
8. Depth of drilling.
9. Completion and production techniques.
10. Water drive, gas-cap drive, or dissolved-gas drive.
11. Secondary-recovery operations.
12. Conservation practices.
13. Ultimate recovery per acre anticipated for each horizon.

VIII. *Production statistics and reserves, using latest data available*

IX. *Bibliography*

DOCUMENTATION

Documentation is systematic citation of source material that gives a report authority, credits properly the work of others, and guides those readers who wish to pursue a subject further. Many systems of documentation are in use, any one of which may be satisfactory if it is used consistently and if the reader can use it efficiently.

A common form of documentation for reports in the field of the earth sciences is that recommended in a pamphlet by the United States Geological Survey to its staff members. This form, which is used in this book, is relatively simple and easy for both the writer and the reader to use. It is also relatively inexpensive to use for both the typist and the printer because there is no need for time-consuming care either in getting footnote references at the bottom of the proper page or in making multiple entries in the bibliography.

This bibliographic form seems to be gaining favor. According to the pamphlet referred to above, this form has ". . . been adopted by the editors of the American Journal of Science, Journal of Geology, Journal of Paleontology, Bulletin of the Geological Society of America, and U. S. Geological Survey."

Dobrin (1954, p. 147) states: "Because uniformity in reference citation among related journals has obvious advantages to authors and readers alike, the present editor, with the concurrence of the Publications Committee, is adopting the U. S. Geological Survey's system for *Geophysics*."

The U. S. Geological Survey's pamphlet, from which permission has been granted to quote herein, describes the form of ". . . bibliographic references commonly used in geological publications" as follows:

Bibliographic lists. —Lists of publications are placed under the heading "Literature Cited" if all are referred to in the text, and "Selected Bibliography" if the list is more extensive.

Order of items in citation. —The order of items in citations is as follows:

1. Name of the author cited (surname first, initials or given name next), followed by a comma. If there is only one given name, it is written in full, as Balk, Robert; if more than one, only initials are used, as Moore, R. C.
2. Year, followed by a comma.
3. Title of work cited (exactly as to spelling and abbreviation and, as a rule, in full), followed by a colon.
4. Name of a periodical or of a series of publications in which the paper cited appears, with volume or number (in arabic numerals), exact page or pages referred to (roman or arabic, as in work cited), plate or figure (arabic), and finally, if it seems necessary for identification, place of publication and publisher's name. Citations of papers published in serials should include both the title of the paper and the title of the serial. Some typical citation (p. 3) should be examined in detail, as to punctuation, capitalization, order of items, and abbreviations.

Order of citations in lists. —The citations are listed in alphabetical order by the name of the author and chronologically under the author. All of an author's individual publications are listed first, then those written with coauthors are listed in alphabetical and chronological order—considering each grouping of authors as a unit. After the first listing use a dash instead of repeating the name or names. One dash takes the place of all the names in the previous citation . . . Complete paging is required for chapters and articles appearing in periodicals, but not for independent publications . . .

Form of reference in text. —In text, reference is made to the author, year of publication, and specific pages or illustrations: "The group was discussed by Reeside (1927a, p. 5-7; 1928, p. 35), and by several other authors (Imlay, 1938, p. 15, 80-83; Cobban, 1942, p. 67; Kummel, 1948, p. 13, 28)."

Unpublished information. —Personal communications are referred to in the text and in footnotes but are not listed as literature because they are not available to the reader. Unpublished reports, including U. S. Geological Survey open-file and other manuscript reports, come under this classification. Exception may be made where reports are in process of publication.

Capitalization. —In English titles of books or articles only the first word, proper nouns, and proper adjectives are capitalized; in titles of English serials principal words are capitalized; in foreign citations the particular national practice is followed throughout, except that the first word of a society's name or a series of publications (or the abbreviation for it) is capitalized. Adjectives formed from the names of countries are capitalized.

STYLE

If a report is written for a definite publication, the style of that publication should be ascertained and followed; if the report is not for publication, the writer should select a style and follow it. Abbreviation, capitalization, compounding, use of numerals, punctuation, tabular form, and references must be correct, but they must also be consistent. Commercial publishers and learned societies usually have style books, and it is suggested that the prospective writer obtain one of these.

Some style manuals to be recommended are the *United States Government Printing Office Style Manual* (1945), *Manual of Style* (1937), and *Words into Type* (Skillin and Gay, 1948). Further information on abbreviation is available in *Abbreviations for Scientific and Engineering Terms* (1941).

The preparation and reproduction of illustrations cannot receive full consideration here. Again the reader is referred to handbooks on the subject: *Preparation of Illustrations for Reports of the United States Geological Survey* (Ridgway, 1920), which also includes brief descriptions of processes of reproduction, and *Time-Series Charts* (1947).

SUMMARY

Writing scientific reports is one of the most important tasks that a scientist is called upon to do. Whether working at a frontier of knowledge or supervising an engineering project, he must describe his work and its results if he is to be a useful member of the organization for which he works and of the society in which he lives.

Organization of the material and the presentation of it are tasks that only the scientist himself can perform. He may and should get advice and suggestions from others, but the performance itself must be his. He must first organize his material, to paraphrase the Golden Rule, as he would have it organized if he were one of the readers. Then, keeping the same rule in mind, he must present the material clearly, simply, and straightforwardly.

There is really no easy way to write a report. It is a task of organizing and reorganizing, writing and rewriting, which Shaw's "Ten Commandments for Technical Writers" (1955) sums up as follows:

1. Thou shalt remember thy readers all the days of thy life; for without readers thy words are as naught.
2. Thou shalt not forsake the time-honored virtue of simplicity.
3. Thou shalt not abuse the third person passive.
4. Thou shalt not dangle thy participles; neither shalt thou misplace thy modifiers.
5. Thou shalt not commit monotony.
6. Thou shalt not cloud thy message with a miasma of technical jargon.
7. Thou shalt not hide the fruits of thy research beneath excess verbiage; neither shalt thou obscure thy conclusions with vague generalities.
8. Thou shalt not resent helpful advice from thy editors, reviewers, and critics.
9. Thou shalt consider also the views of the layman, for his is an insight often unknown to technocrats.
10. Thou shalt write and *rewrite* without tiring, for such is the key to improvement.

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Chapter 40

VALUATION AND SUBSURFACE GEOLOGY

John D. Todd

The art of valuing producing petroleum properties (and it is more of an art than a science) has grown up in the oil business contemporaneously with the maturing of subsurface geological knowledge. Of course, both started in Colonel Drake's time from zero, and during the past 98 years, valuation has at times out-distanced geology. In other decades geological knowledge has grown faster than knowledge of valuation.

When Professor Wright investigated the oil business at the close of the Civil War, he found that subsurface geology was a maze of superstitions and that valuation attempts were dominated by promotion. As thousands of wells were drilled and millions of barrels of oil were yearly produced, many things were learned about oil reservoirs—both in the drilling of new wells and in the performance of the old wells. Wright found that the average life of a well was 18 months in 1865, whereas shortly thereafter wells were being sold on twice that payout period.

One of the earliest standards of valuation was the "days of payout," on which much Allegheny production was sold. It was common custom in early Pennsylvanian days to value net daily barrels of settled-oil production at one thousand times the price of oil. For instance, a property producing 1000 net barrels per day would be worth $3,000,000 if oil was selling at $3.00 per barrel. Although this method gave no consideration to subsurface geology (and properly so, since almost nothing was known about it), it represented a composite of oil men's opinions on operating costs, probable rate of decline, and expected profits. Even today, the net daily barrels produced is used as a yardstick in evaluating some properties.

As the oil industry grew, some systematic operators began to keep charts on the wells and to draw curves on their production. As every well was always produced at its maximum rate, these charts recorded not only the decline of daily production but also the decline of daily *capacity*. As none of the wells ever increased, these curves became known as decline curves. From the study of many of these curves, it became apparent that in many fields, the decline followed a certain pattern. Observers found that they could draw an average curve of all the wells, and could fit any well curve into a portion of a master curve—and that, properly placed, the future performance of that well followed the master curve. From this fact evolved the Law of Equal Expectations expressed as: "If two wells under similar conditions produce equal amounts during any given year, the amounts they will produce thereafter, on the average, will be approximately equal regardless of their relative ages." In other words, a 50-barrel-a-day well that is 10 years old will produce about as much oil in the future as a 50-barrel well that is 1 year old.

Of course, decline curves had little to do with subsurface geology. Our knowledge of subsurface geology was expanding each decade, but figuring reserves was a matter of daily production figures and graph paper. Family curves, composite curves, running averages, comparative ratios, cumulative-productive curves—all had their sponsors and special uses. Plotting the curves on logarithmic or semi-logarithmic papers made a straight line out of the curves and aided in their projection.

The matter of estimating how much oil a well would produce in the future from facts on its past production, and the past production of other wells, attained a high degree of proficiency with an exacting standard of accuracy. The future production of a well could be closely predicted, with or without a knowledge of subsurface geology. It is still true that when decline curves are available (as in the later life of wells, when they will no longer make their allowable, and are thus being produced at capacity) a proper projection of the curve gives the best possible estimate as to both the ultimate production of a well and the rate of that production.

PRORATION

One of the really great changes in the oil industry came in about 1931 with the advent of overproduction. The oil industry has always been plagued by overproduction and periodic price declines. As early as 1926 legal efforts were made to curtail production equitably (always claimed in the cause of conservation, but actually to prevent price decline). The development of the giant East Texas Field in a financial depression paved the way to permanent proration by statute. Proration meant that wells would henceforth produce not at capacity, but at their MER (Maximum Efficient Rate), a percentage thereof, or some other alleged equitable system of restriction. This also meant payouts in terms of years instead of weeks, and the need of much more capital—the first well no longer would finance the drilling of all the later wells on a large tract; money had to be borrowed.

As wells no longer produced at capacity, there were now no decline curves; so all of the curve liturgy had to be replaced by some other method by which the ultimate production of a lease could be predicted early in its life. Loans were to be arranged, mergers made, unitizations accomplished, and properties to be bought and sold—the oil business had to go on in spite of proration, and some new scheme of valuation had to be adopted.

Fortunately, subsurface geology had grown greatly during the decline-curve days. Much had been learned about structure, reservoir rocks, connate water, explusive mechanisms, and a host of other important items. In arriving at an estimate of recoverable oil (usually referred to as reserves) the estimator could use all of these data. With all of this modern information, some of the speculation about the subsurface geology of the reservoir was eliminated, and the reserve estimate was rendered progressively safer.

While proration was still an infant, the electric log came to the aid of subsurface geologists. It is hard to overestimate the utility of electric logs in any phase of subsurface geology, but valuation as we know it today in most areas could not exist without these logs. In fact, reliable reserve estimates are often made with no other information except a map and a set of electric logs.

MARKET VALUE

Almost all valuations fall into two classes: (1) market valuation, or (2) the engineering or analytical valuation. Little has been written about the market value of a petroleum property except in the law books. The fair market value is said to be "the amount that would be paid on a certain day by an informed buyer, able and willing to buy, and accepted by an informed seller, willing but not forced to sell." This theoretical trade made by two theoretical parties is the courts' attempt to determine what a property is *really* worth at a specific time. For most legal purposes, it is this "fair market value" in which the judge and jury are interested, and which they are trying to determine. For some tax and estate purposes, this fair market value is the appraisal that is needed, and in such cases no amount of counting acre-feet and calculating will do. One must attempt to reconstruct what would have been a fair trade at the stated time.

The best evidence of fair market value is an actual sale of that particular property, or some part of it, at that time. But, of course, that never happens; disputes do not occur when the answer is known. Litigation and tax disputes arise in the area of uncertainty, and usually are due to a conflict between optimists and pessimists. If there were a sale, a fair sale, of that particular property at that time, one could establish fair market value without knowing any subsurface geology, or for that matter, without knowing anything about the oil business.

But fair market value must always be proved by comparison, inference, and analogy. The next best evidence is records of sale from county deed records of adjoining properties or of similar properties elsewhere. Oil companies keep records of transactions submitted to them, and these tend to show fair market value. Also, traders in that area frequently know of transactions or near transactions on similar properties, which are admissible evidence in some proceedings.

As soon as one begins to study adjoining or similar properties, he is dealing in subsurface geology. An adjoining lease may raise such questions as: Is it up or down structure? It is a gas- or water-drive reservoir? Does the producing section thicken or thin in that direction? Does the reservoir increase or decrease in porosity and permeability in that direction? And, when similar properties are considered, it is almost entirely a study of subsurface geology—and the compared property is always similar in some respects and dissimilar in many others. And the larger the area covered, the more subsurface geology needed.

Most disputes about market value end in a compromise, somewhere between the optimists and the pessimists. But, in those cases which proceed to final legal adjudication, victory usually comes to the appraiser who works the hardest and knows the subject best—there is so much subsurface geology to know, and so much evidence on both sides, that either side can win.

ENGINEERING VALUATIONS

In contrast to fair market value, an engineering valuation is an analytical study of every known fact about a property to arrive at a theoretical value (as of now or any other time). Such valuation assumes (1) that the property will produce a certain amount of money—the computed reserve at some assumed price, (2) that it will cost a certain amount of money to develop and operate the property (except in the case of a royalty), (3) that the difference between gross income and expenses is the future profit—which when discounted at some assumed rate of interest gives a present value of the property.

Such engineering valuations are usually the basis of mergers and unitizations; they are required by banks and insurance companies in the making of loans; and they form a trading background for most sales of properties. All major companies make and constantly revise such valuations on their own properties as a kind of perpetual inventory. The largest oil companies keep up such reserve estimates on all producing properties (those of all of their competitors as well as their own) to stay posted on their relative reserve position, and to help their pipe-line subsidiaries in their competition for control of the available oil.

In spite of the fact that these valuations are in daily use by every part of the oil and gas business, and although they are computed on large, expensive mechanical calculators that carry the answer out to four decimal places—still they are all based on assumptions and are far from exact. Every engineering valuation assumes (1) some continuity of reservoir rock and porosity, (2) some amount of connate water, (3) a recovery factor, (4) a future rate of production, (5) a future price for oil or gas, (6) future costs, and (7) some discount factor or factors. In addition to the above seven estimates, at least some of the following factors are estimated in every valuation (usually one half of them are estimates); (8) productive acreage, (9) thickness of productive zone including gas-oil and oil-water contacts, and the amount of cross section that is porous, (10) percentage of porosity and how permeable, and (11) shrinkage factor.

As mentioned above, quite reliable valuations can be made by a geologist who is well acquainted with the general area if he uses only a map and a set of electric logs; and very many of the valuations are based only on that data. Rather than bemoaning the mistakes in valuations, we should marvel that they are so near right and have formed a basis on which the oil and gas business could grow to where its present annual production exceeds the annual national production of coal, iron, copper, gold, silver, and all other metals combined.

FIGURING THE RESERVE In actual practice the figuring of the reserve by the engineering (often called the volumetric) method involves (1) delineating the reservoir area and thickness, and calculating the acre-feet of gross rock, (2) figuring the amount of pore space in that reservoir, (3) deducting the part of space occupied by water, (4) figuring the oil or gas in place, (5) deducting the shrinkage it will suffer on coming to atmospheric pressure and temperature, (6) deducting the part of oil or gas that will not be recoverable by present methods and will therefore be left in the ground, and (7) deducting the past cumulative production—what has already been produced.

For oil, these steps are usually expressed in the following formula:

$$R = 7758 \times A \times T \times P \times (1 - I) \times S \times F$$

in which R is the recoverable reserve.

The 7758 is the number of barrels of tank-stock oil needed to fill one acre, one foot deep.

The A is the number of acres in the reservoir. This factor requires the most careful and detailed kind of subsurface geology. Some important information is almost always lacking, a fact which requires the most thoughtful consideration of what is known and the drawing of the most reasonable inferences. It has been said by some of our most eminent valuation experts that *properly dimensioning the reservoir is the greatest single source of error in reserve estimates.*

The T is the thickness of the producing measure. This factor is ordinarily arrived at from electric logs, supplemented by such coring or cuttings and core analysis as it obtained from that property or any related property. This procedure always involves the picking of the top of the formation, frequently involves the location of a gas-oil contact, and usually requires the selection of an oil-water contact. Experience in the general area of the property is of commanding importance in the making of these various judgments. There is much to know that is not written in books. An opportunity to see many wells cored and logged, to produce them, and to be intimately acquainted with their entire history—this type of experience, to which geologists with major oil companies are daily exposed, is the best possible teacher in such matters.

The P in the formula is the porosity. Frequently no information is available from the particular wells—then an estimate for normal porosity in that formation at that depth is used. Often a little core analysis at one or two points in the producing horizon is available—this fact is carefully placed on the log and an effort made to realize whether the data represent normal porosity or whether the cores were from a good streak, or perhaps a tight part of the horizon. Often only porosity data from other scattered wells in the field are available—in such cases an educated guess is made and porosity is assumed to be the same under the entire property.

Although a rock may be porous, it also must be permeable to be a producible petroleum reservoir. If sufficient permeability (the continuity of the pore spaces, which permits passage of fluids through the pores) does not exist, the fluids in the porous reservoir cannot be produced—or they can be produced only so slowly that they are not commercial.

Fracturing may contribute to the porosity of limestones. It is notoriously hard to recover cores from lime, and usually cores give no information as to total amount of fracturing. The amount of fracturing is sometimes estimated by computing what the capacity of the well should be from its total section, bore hole, porosity, and permeability—then attributing any excess capacity to fractures. (Engineers can compute anything if you let them make a few innocuous assumptions while they get their slide rule out of the case.) Cores taken with a diamond bit quite often result in the recovery of fractured cores intact, so that estimates of fracture porosity can be made.

Measurement of porosity in the now popular reef, conglomerate, or other "heterogeneous" reservoirs introduces new problems. The microlog shows promise of enabling one to make a good estimate of the amount of permeable zone in such a section, although the percentage porosity still must be obtained by coring or estimation. If one has micrologs nearby, he can pretend that the section will be the same elsewhere. If one has only electric logs, he just does his best, remembering that assuming 50 percent of the reef to be porous seems to be about the average used.

Porosity in producing fields varies from 2 to 40 percent, with the average being between 20 and 25 percent. It is a great variable. The porosity between wells is not known, even though one may have measured it in cores from the producing section of the wells. It is always assumed that the well bores are representative of the reservoir. Performance of the wells themselves is often some help—good, high-capacity wells are not made in thin, nonporous sections.

Connate or interstitial water (denoted by I in the formula) is nonproducible water contained in the reservoir rock along with the oil and/or gas. It is thought that the formations, when laid down, contained sea water in the available pore spaces and that the reservoir rocks retain this sea water (sometimes called fossil water) until it was driven out by the migrating gas and oil. The gas or oil displace most of the sea water, but not all of it—some of it is held by capillary forces and remains as a coating of water around each sand grain. Producing formations nearly always contain some interstitial water, which occupies part of the pore space and reduces the oil or gas reserve.

The amount of connate water is extremely difficult to determine. Cores are often hard to secure and are usually contaminated by drilling fluids. Only rarely are cores taken with oil-base mud in order to prevent flushing of the core by water from drilling mud. The "restored state" method gives close approximations by determining how much water a core should retain in the face of gas or oil flushing. In this method, capillary equilibrium similar to that existing in the reservoir is established in the laboratory within the core. Connate water can often be estimated from a study of electric-log resistivities. Connate water varies between 0 and 60 percent; it will average 20 percent in good porous sands and 30 percent in tight, impermeable sands. Since it is a reducing factor, it is dealt with as $1 - I$; thus, 20 percent connate water is $1 - 20$ percent, or a multiplier of 0.80.

The shrinkage factor is denoted by S in the formula. A barrel of reservoir oil shrinks when brought to the lower temperature and pressure at the surface—a barrel of reservoir oil being equal to only a fraction of a barrel of stock-tank oil. This reduction in volume is due almost entirely to the gas coming out of solution when the barrel of oil is brought to the surface—a barrel of oil with hundreds of feet of gas in solution in it occupies more space than that same barrel of oil with the gas removed. The more gas in solution, the greater is the shrinkage; and the deeper the reservoir, the greater is the amount of gas in solution—so that, in general, the deeper the well, the greater the shrinkage factor. The shrinkage is usually measured in the laboratory or estimated from the gas-oil ratio of the wells and the gravity of the oil. This shrinkage is a substantial reducing factor where ratios in excess of 2000:1 of solution gas are encountered; the factor may be 50 percent or less. At great depths it takes over two barrels of such reservoir oil to make one barrel of stock-tank oil.

The recovery factor is designated as F in the formula. Knowing how much oil or gas is in the reservoir, how much of this is going to be producible—how much will be left in the reservoir when the field is abandoned? *This is always an estimate; no one can know.* The recovery is influenced by many things, by the amount of gas in solution, the viscosity of the oil, the rate of production, the primary expulsive energy, the price of the oil, and a number of other things. Recovery factors vary widely, but generally are within the following ranges: 20 to 40 percent of the oil in place for dissolved-gas-drive fields, 30 to 70 percent for expanding gas cap plus gravity, and 50 to 80 percent for fully effective water drive.

A HYPOTHETICAL CASE An example always best illustrates the actual workings of such a formula, and affords an opportunity to point out the dependence of a valuation on subsurface geology. Assume that one is to evaluate a conventional seven-eighths lease on a 160-acre tract with eight wells which are located midway down the flank of a rather steep Gulf Coast anticline and which are producing oil by effective water drive from a sand at −5000 feet.

A map is secured showing the location of all the wells on the structure, plus electric logs of all the wells in the field. A structure map is drawn on the top of the producing formation—where several sands produce, a structure map should be drawn on each sand. This procedure involves carefully picking the sand "top" on each well in the field, which is checked against all obtainable core data to verify that what appears to be top of sand is the first productive sand encountered. After the structure map is drawn, an isopachous map of the producing sand is prepared. This map is based on "effective sand"—from a minute examination of the detailed section ($100' = 5''$) of the electric log, plus all known coring, core analysis, caliper log, gamma-ray log, drilling-time chart, and any other data obtainable. Shale and/or hard streaks are excluded in order to isopach only the actual producing section.

After the isopach is drawn, each isopach interval is planimetered to give the actual number of acres situated in that zone of thickness. Thus, the area between the 50- and 45-ft. isopach lines is planimetered and assumed to have a sand thickness of 47½ ft. Only a single tract of 160 acres is to be valued, and it is found that 48 acres is underlain by 40 ft. of effective sand, 68 acres by 36 ft. of sand, and 44 acres by 32 ft. of sand. Thus, in valuing the 160 acres, three valuations are made; or, all three segments are combined to get a composite of acre-feet of sand. To composite these figures, multiply 48 × 40 to get 1920 acre feet, 68 × 36 to get 2448 acre feet, and 44 × 32 to get 1408—or an aggregate of 5776 acre feet of producing sand under the 160 acres (the product of A, acreage, and the T, thickness, of the formula). It is already known that oil fields in this trend can be expected to produce 400 barrels per acre-foot. An experienced valuator in the trend thus could estimate around 2,310,400 barrels (5776 × 400) of ultimate recovery.

It is found that when the eight wells on the lease were drilled, no cores were obtained. It is learned that core laboratories ran cores from a well on an adjoining lease; average porosities of 21, 23, and 24 percent were obtained from three cores. The Gulf Company has run porosities, which average 23 percent on most of its wells. Permeabilities averaged 550 millidarcys. It is concluded that 22 percent is about the average porosity for the lease being valued, and that permeabilities are satisfactory. This conclusion appears to be in line with known porosities in nearby fields producing from the same formation and on strike.

The next factor in the formula is I (interstitial or connate water). In an older field, the amount of connate water will probably involve an estimate—as in the early days there were no connate-water determinations. In fact, many then thought connate water did not exist. If no connate-water determinations are available, estimates can be made based on known determinations in similar formations in on-strike fields. Connate water ranges from 10 to 50 percent of the pore space; and, in estimating, around 20 percent in good porous reservoirs and 30 percent in mediocre reservoirs are fairly safe averages.

In this field, the development has been more recent—all of the wells have electric logs. Cores from one nearby well were analyzed by the restored-state method in the Texas Company's laboratory; some companies do systematic core determinations on all of their own wells and sometimes on adjacent wells. Three pieces of cores were analyzed on this well and showed connate-water content of 35, 32, and 36 percent. Comparison with the electric log indicates that the higher values came from the normal parts of the sand and that the 32 percent was from the most porous part of the sand.

It is learned that the Shell Company has made connate-water determinations in their own laboratory on all the cores taken from their wells on this structure. The valuator has a geologist friend at Shell, and while he cannot see their core-analysis reports, he is able to "swab" the information that they are using 33 percent for connate water. Putting all of this information together, he concludes that 34 percent is probably a safe factor for the interstitial water.

Fortunately, a nearby well logged the producing sand below the water contact, so that the resistivity of this sand saturated with water (R_0 factor) is known. Thus, the R_0 factor is known, and from the electric log the probable connate-water content is computed as 35 percent—an amount which appears to confirm the other data.

With a porosity of 22 percent and connate water of 34 percent, reference to Figure 40-1 shows that there are 1126 barrels of available pore space per acre-foot in the reservoir. All kinds of charts, graphs, and short cuts are used by various reservoir engineers. This combination of porosity and connate water is one of the more useful ones and saves much routine calculation in both oil and gas problems. In the present instance, it enables one to substitute 1126 barrels of pore space for the $P \times (1 - I)$ part of the formula. Therefore, 5776 acre-feet $\times$ 1126 barrels of available pore space equals 6,503,776 barrels of space under the lease—or, in this instance, 6,503,776 barrels of reservoir oil in place.

The S or shrinkage factor is largely dependent on the amount of dissolved gas and the gravity of the oil. Gas-oil ratios are regularly determined by various state regulatory bodies and are almost always available. The wells on this lease produce oil of 35° gravity with an average gas-oil ratio of 510:1. Referring to published charts and curves, one finds that the shrinkage factor (sometimes called formation volume factor) for a 510:1 ratio and 35° gravity oil will be 78 percent; or that a barrel of oil in the reservoir is only equal to 78/100 of a barrel when it reaches the stock tank and is ready to be sold. This is always a reducing factor but at shallower depths and with under-saturated crudes, it is not too large—at great depth with large amounts of dissolved gas, the neglect of this factor gives greatly exaggerated reserves.

The last item in the formula is F for recovery factor, which is the percentage of the inplace oil that the estimator believes is recoverable. It is always an estimate, and all too often just an off-hand guess. It is one of the greatest sources of errors in estimates. Many things go into a recovery factor, and lots of them are not found in the science books.

Chief among the scientific factors affecting recovery is the type of explusive energy that is bringing the oil to the bore hole, and perhaps removing the oil from other leases. If there is a fully effective water drive, the lease high on the structure will have a very high recovery factor—usually recovering more oil than could be calculated to be under it. This fact is due to the Law of Capture; the oil belongs not to the lease owner under whose property it is discovered, but to the well owner who produces it (reduces it to capture). Courts are making some feeble efforts to get away from the Law of Capture, but it is still very strong in most jurisdictions and must always be considered in every estimate of recovery. The workings of the Law of Capture are intimately related to the subsurface geology of the property—and afford the geologically minded operator many opportunities to take advantage of, or to protect himself from, natural drainage.

Just as the top lease in a water-drive field produces all of its own oil and some of all the oil in the down-dip lease—conversely, the edge lease produces only part of its own oil and none of anyone else's oil. How much oil an edge-lease owner will produce depends on the allowable production compared with those of up-dip leases. The down-dip lease always shares its oil with the up-dip leases, but a larger allowable sometimes results in the down-dip lease getting a fairer share. Water encroachment is not always regular; frequently water will intrude through the more porous permeable zones to reach the higher wells—this is particularly true if the up-dip wells are pulled hard. In such cases, the edge lease is left to produce its oil long beyond its computed time. Many edge leases which should have gone to water years ago (if the water level evenly moved up proportionately to the oil withdrawn from the reservoir) are yet producing, and still make their allowable every day.

Big recoveries from the leases high on structure are matters of common knowledge. But enormous recoveries from a lease low on the structure are just as likely if drive is from gas and the dip is steep. Gas drive is like gravity drainage under high pressure—and the edge lease will produce all of its oil and all of the oil that runs down into it, whereas, the top lease will produce only part of its oil and then go to gas.

The study of who gets the oil is a fascinating combination of subsurface geology, some engineering, and an analysis of various statutes and regulations of oil and gas boards. A change in field rules or in the method of computing allowables can move the recoverable reserve from one lease to other leases. By the rules of oil and gas boards, the Law of Capture can be modified or annulled, and the to-be-produced oil can be moved from one lease to another—just as the President transfers funds from the Justice Department to the Labor Department. Such transfers are not spelled out in the engineering terms of the rule change—but they are there in between the lines, and they become apparent when one analyzes the value of various leases. This matter does not come up when an entire field is considered—but one company seldom owns an entire field.

Other scientific factors which contribute to the recovery factor are the gravity of the oil, its viscosity, the amount of dissolved gas (the viscosity goes up as you lose the gas), the porosity, and the relative permeability of the reservoir rock. The rate at which the field will be produced has a bearing on the recovery factor.

Aside from the engineering angles, the political implications of the situation have some bearing on the recovery factor. An operator's political connections or antipathies may influence his allowables. The brother-in-law of a member of the oil and gas board seldom gets an unfair allowable—that is a positive factor in the recovery under his lease; it could be a negative factor if you are valuing the adjoining lease.

It is ascertained that the bottom-hole pressures do not decline in the 160-acre lease and that water encroaches into the edge wells. It is concluded that there is a fully effective water drive. The producing formation covers a vast area and logically might contain an expanding water blanket. Other operators in this field consider it to be water drive also.

The oil is of 35° gravity, and the 500-millidarcy permeability is fair One would expect water drive to be of the lower order of effectiveness and tentatively estimate a recovery factor of 50 percent. The lease is half way up the structure, so it will surely draw some of the oil out of the down-dip leases; some of the oil will be lost to the up-dip leases. Consideration of the amount of oil the reservoir has produced, how far the water has advanced, and how much farther it must come to reach the lease being valued leads one to the conclusion that about as much oil will be gained as will be lost by drainage. Therefore, the recovery factor is left at 50 percent.

. Using a shrinkage factor of 78 percent and a recovery factor of 50 percent, 6,503,776 (reservoir oil in place) × 78 percent (shrinkage) × 50 percent (recovery factor) = 2,536,472 barrels of original recoverable oil under the lease. An examination of production records shows that the lease has already produced a total of 289,336 barrels; this deduction leaves 2,247,136 barrels of remaining reserve under the lease. There is also contained in this oil 1146 million cubic feet of gas (2,247,136 × 510); but, as there is no present means of recompressing this gas (to raise it to pipe-line pressure) and no market for the low-pressure gas, no value will be included for the gas. As the operator has a full seven-eighths lease, he owns 1,966,224 barrels of oil and 1003 million cubic feet of gas.

Now that it has been concluded that 1,966,244 barrels of oil can be recovered by primary recovery means, how many dollars will this oil sell for? Will the price of oil go down, or will it go up? The usual procedure is to assume that the price of oil will remain the same (of course it never has, but that is an easy way out). The operating costs are likely to go down and the value of dollars to increase if oil declines in price; and if oil goes up in price, operating costs will probably increase and the purchasing power of the dollar will decline. The present price of 35° oil in the area of this lease is $2.78 per barrel. So, multiplying 1,966,244 barrels × $2.78, one finds that the anticipated sale price of the operator's oil from this lease is $5,466,158.32. It will be left to the executive or operator who receives the report to predict the future price of oil (since that is really a part of management's duties), and the report assumes that all this oil will be sold at $2.78 a barrel.

When one attempts to estimate the future price of oil, he has left the field of geology and entered economics. When he attempts to estimate the operating costs of bringing this oil to the surface, he is in the field of accounting. But, obviously, it will cost money to produce any oil (unless it is royalty oil) and those costs must be deducted from receipts before the profit will be known. Again the usual procedure is to assume that the costs of labor, materials, and other items will remain the same. Examination of the books of the operator indicates that it now costs $0.28 per barrel to produce and handle the oil, including advalorem and severance taxes. The wells are all flowing and with good water drive will flow all their oil—but as they grow older reworks will come oftener. So, for the future an increased cost is assumed to be $0.31 per barrel. Deducting this, one finds that the future net profit from oil will be $4,856,622.68. The salvage value at abandonment, estimated to be $40,000.00, may be added to the value of the oil.

Actually, it will cost more to produce the oil if the producing rates are small, as more years of operation are required. Operating costs, aside from taxes, are fairly uniform for a given well regardless of producing rate. Therefore the per-barrel cost becomes higher as the rate of production becomes lower. What kind of allowables will these wells have in the future? Will they be permitted to produce more, or will they be required to produce less? Much depends on economic trends. But again, in this case, it is assumed the status quo will continue. The lease now has an allowable of 65 barrels of oil per day per well, which amounts to 15,600 barrels per month. At that rate the lease will produce for 144 months, or 12 years, and will produce a monthly income of equal monthly payments for that period.

Now, what is such a future income worth at the present time? What is money worth? Money is loaned at different rates, depending on who the borrower is and of what his security consists. Normal discount rates used for oil evaluations vary from 3 to 6 percent. The $4,856,622.68 discounted at 5 percent per year yields a present value of $3,587,101.51. To this amount is added the present worth of the $40,000 salvage 12 years hence, which is $22,289.48. This gives a total present worth of $3,609,390.99. In some valuations, no discount is figured. In such cases, the recipient of the valuation report is left to make his own estimate of what that future income is worth now.

A valuation report on oil should also mention the amount of gas to be produced—as some market may be developed for this gas. Also, the report should mention any geology pointing to deeper possibilities under the lease, but no value should be accorded unless the deeper sands have been drilled and tested.

In conclusion a word of warning: The latest production data on the lease should always be obtained—an actual trip to the property should be made by the appraiser just before he signs the report. The gauger on the lease not only knows how each well performed last month or last year; he knows how it performed yesterday afternoon and this morning. The production of each of the wells should be carefully checked—gas-oil ratios, pressures, and water percentages should be measured. Despite all the formulas, maps, logs, etc., the value of the property is the ability of some holes in the ground to produce material that will sell. If those wells stop producing material that sells, there is nothing much to value. The writer knows of wells that have declined as much as 75 percent while a valuation was being prepared—if a last minute check-up had not been made, the declines never would have been suspected. When valuing an oil or gas well, always remember Mark Twain's definition of a mine, "A hole in the ground owned by a liar."

GAS PROPERTIES

The geology of the structure and the intimate study of the reservoir rock itself is the same for the valuation of gas property as for oil. But, because gas is dealt with as a vapor and is so highly compressible, some other considerations enter into gas valuations.

In oil properties, the deeper the well, the greater the shrinkage factor: 1000 barrels of reservoir oil at 5000 feet is usually more stock-tank oil than 1000 barrels at 10,000 feet—or, to put it another way, 20 feet of sand usually contains more recoverable oil at 5000 feet than at 10,000 feet. But just the opposite is true for gas—20 feet of sand at 10,000 feet contains nearly twice as much recoverable gas as the same 20 feet of sand would contain at 5,000 feet. Oil at greater depth is worth less because of the excessive cost of drilling deep wells—gas values are affected less because gas wells are always so widely spaced, usually on 320- or 640-acre units. By and large, oil decreases in value with depth, but gas increases in value with depth.

Assume that the same 160 acres overlies gas instead of oil. In gas valuation, the formula begins with 43,560 as the number of cubic feet in one acre (one always deals with cubic feet in gas—mcf, thousand cubic feet—or mmcf, million cubic feet). In order to obtain cubic feet of reservoir space it would be necessary to multiply by porosity and connate-water factors—in this case again refer to Figure 40-1 and find that for 22 percent porosity and 34 percent connate water, there are 6512 cubic feet of gas space in each acre foot. Again, using 5576 acre feet of reservoir, one finds that there are 36,310,912 cubic feet of storage space in the reservoir. At atmospheric pressure and temperature, this reservoir would contain 36,310,912 cubic feet of air, and would hold that much gas.

But this reservoir is not at atmospheric conditions; it is under very high pressure and is always much hotter than the atmosphere. According to Boyle's Law, as the pressure is increased, the amount of gas a reservoir contains also increases. If the pressure is doubled (temperature remaining the same) there is twice as much gas—so that each time an atmosphere of pressure (14.7 lbs.) is added, a reservoir full of gas, or 36,310,912 cubic feet is added.

If bottom-hole pressures have been taken on the gas wells, exactly the pressure existing in the reservoir will be known. Or, if the well-head pressures,

PERCENT POROSITY

CONNATE WATER PERCENTAGE	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
10	698 3920	768 4312	838 4704	908 5097	978 5489	1047 5881	1117 6273	1187 6665	1257 7057	1327 7449	1396 7841	1466 8233	1536 8625	1606 9017	1676 9409
11	690 3877	760 4265	829 4652	898 5040	967 5428	1036 5815	1105 6203	1174 6591	1243 6978	1312 7366	1382 7754	1420 8141	1519 8529	1588 8917	1657 9304
12	683 3833	751 4217	819 4600	888 4983	956 5367	1024 5750	1092 6133	1161 6517	1289 6900	1297 7283	1365 7667	1434 8050	1502 8433	1570 8817	1638 9200
13	675 3790	742 4169	810 4548	877 4927	945 5306	1012 5685	1080 6064	1147 6443	1215 6822	1282 7200	1350 7579	1417 7958	1485 8337	1552 8716	1620 9095
14	667 3746	734 4121	801 4495	867 4870	934 5245	1001 5619	1068 5994	1134 6368	1201 6743	1268 7118	1334 7492	1401 7867	1468 8242	1535 8616	1601 8991
15	659 3703	725 4073	791 4443	857 4813	923 5184	989 5554	1055 5924	1121 6294	1187 6665	1253 7035	1319 7405	1385 7775	1451 8146	1517 8516	1583 8886
16	652 3659	717 4025	782 4391	847 4757	912 5123	978 5489	1043 5854	1108 6220	1173 6586	1238 6952	1303 7318	1369 7684	1434 8050	1499 8416	1564 8782
17	644 3615	708 3977	773 4339	837 4700	901 5062	966 5423	1030 5785	1095 6146	1159 6508	1223 6869	1288 7231	1352 7593	1417 7954	1481 8316	1545 8677
18	636 3572	700 3929	763 4286	827 4644	891 5001	954 5358	1018 5715	1081 6072	1145 6429	1209 6787	1272 7144	1336 7501	1400 7858	1463 8215	1527 8573
19	628 3528	691 3881	754 4234	817 4587	880 4940	943 5293	1005 5645	1068 5998	1131 6351	1194 6704	1257 7057	1320 7410	1382 7762	1445 8115	1508 8468
20	621 3485	683 3833	745 4182	807 4530	869 4879	931 5227	993 5576	1055 5924	1117 6273	1179 6621	1241 6970	1303 7318	1365 7667	1427 8015	1490 8364
21	613 3441	674 3785	735 4129	797 4474	858 4818	919 5162	981 5506	1042 5850	1103 6194	1164 6538	1226 6882	1287 7227	1348 7571	1410 7915	1471 8259
22	605 3398	666 3737	726 4077	787 4417	847 4757	908 5097	968 5436	1029 5776	1089 6116	1150 6456	1210 6795	1271 7135	1331 7475	1392 7815	1452 8154
23	597 3354	657 3690	717 4025	777 4360	836 4696	896 5031	956 5367	1016 5702	1075 6037	1135 6373	1195 6708	1254 7044	1314 7379	1374 7714	1434 8050
24	590 3311	649 3642	708 3973	766 4304	825 4635	884 4966	943 5297	1002 5628	1061 5959	1120 6290	1179 6621	1238 6952	1297 7283	1356 7614	1415 7945
25	582 3267	640 3594	698 3920	756 4247	815 4574	873 4901	931 5227	989 5554	1047 5881	1106 6207	1164 6534	1222 6861	1280 7187	1338 7514	1396 7841
26	574 3223	632 3546	689 3868	746 4190	804 4513	861 4835	919 5158	976 5480	1033 5802	1091 6125	1148 6447	1206 6769	1263 7092	1320 7414	1378 7736
27	566 3180	623 3498	680 3816	735 4134	793 4452	850 4770	906 5088	963 5406	1019 5724	1076 6042	1133 6360	1189 6678	1246 6996	1303 7314	1359 7632
28	559 3136	614 3450	670 3764	726 4077	782 4391	838 4704	894 5018	950 5332	1005 5645	1061 5959	1117 6273	1173 6586	1229 6900	1285 7214	1341 7527
29	551 3093	606 3402	661 3711	716 4021	771 4330	826 4639	881 4948	936 5258	991 5567	1047 5876	1102 6186	1157 6495	1212 6804	1267 7113	1322 7423
30	543 3049	597 3354	652 3659	706 3964	760 4269	815 4574	869 4879	923 5184	978 5489	1032 5793	1086 6098	1140 6403	1195 6708	1249 7013	1303 7318
31	535 3006	589 3306	642 3607	696 3907	749 4208	803 4508	856 4809	910 5110	964 5410	1017 5711	1071 6011	1124 6312	1178 6612	1231 6913	1285 7214
32	528 2962	580 3258	633 3555	686 3851	739 4147	791 4443	844 4739	897 5036	950 5332	1002 5628	1055 5924	1108 6220	1161 6517	1213 6813	1266 7109
33	520 2919	572 3210	624 3502	676 3794	728 4086	780 4378	832 4670	884 4961	936 5253	988 5545	1040 5837	1092 6129	1144 6421	1196 6713	1247 7004
34	512 2875	563 3162	614 3450	666 3737	717 4025	768 4312	819 4600	870 4887	922 5175	973 5462	1024 5750	1075 6037	1126 6325	1178 6612	1229 6900
35	504 2831	555 3115	605 3398	656 3681	706 3964	756 4247	807 4530	857 4813	908 5097	958 5380	1009 5663	1059 5946	1109 6229	1160 6512	1210 6795
36	497 2788	546 3067	596 3345	645 3624	695 3903	745 4182	794 4461	844 4739	894 5018	943 5297	993 5576	1043 5854	1092 6133	1142 6412	1192 6691
37	489 2744	538 3019	587 3293	635 3568	684 3842	733 4116	782 4391	831 4665	880 4940	929 5214	978 5489	1026 5763	1073 6037	1124 6312	1173 6586
38	481 2701	529 2971	577 3241	625 3511	673 3781	721 4051	770 4321	818 4591	866 4861	914 5131	962 5401	1010 5672	1058 5942	1106 6212	1154 6482
39	473 2657	521 2923	568 3189	615 3454	663 3720	710 3986	757 4251	805 4517	852 4783	899 5049	946 5314	994 5580	1041 5846	1088 6111	1136 6377
40	465 2614	512 2875	559 3136	605 3398	652 3659	698 3920	745 4182	791 4443	838 4704	884 4966	931 5227	978 5489	1024 5750	1071 6011	1117 6273
41	458 2570	503 2827	549 3084	595 3341	641 3598	687 3855	732 4112	778 4369	824 4626	870 4883	915 5140	961 5397	1007 5654	1053 5911	1099 6168
42	450 2526	495 2779	540 3032	585 3284	630 3537	675 3790	720 4042	765 4295	810 4548	855 4800	900 5053	945 5306	990 5558	1035 5811	1080 6064
43	442 2483	486 2731	531 2980	575 3228	619 3476	663 3724	708 3973	752 4221	796 4469	840 4718	884 4966	929 5214	973 5462	1017 5711	1061 5959
44	434 2439	478 2683	521 2927	565 3171	608 3415	652 3659	695 3903	739 4147	782 4391	825 4635	869 4879	912 5123	956 5367	999 5611	1043 5854
45	427 2396	469 2635	512 2875	555 3115	597 3354	640 3594	683 3833	725 4073	768 4312	811 4552	853 4792	896 5031	939 5271	981 5510	1024 5750

FIGURE 40-1. Barrels of void space in one acre-foot. Cubic feet of void space in one acre-foot; with percent porosity. One acre-foot = 7758 bbls.; one acre-foot = 43,560 cu. ft.

fluid levels, and the weight of the gas are known, the bottom-hole pressure can be computed. Often the original, bottom-hole pressure can be estimated from the depth of the formation. Normal pressure in post-Eocene sediments on the Gulf Coast increases 46½ pounds per square inch with each 100 feet of depth. There are a few low-pressure and a few high-pressure reservoirs, but not many which vary from the 0.465 rule—which incidentally, is the weight of a column of sea water. When depth in feet is multiplied by 0.465, the approximate bottom-hole pressure is obtained. In this case, 5000×0.465 gives 2325 pounds as the bottom-hole pressure. This 0.465 gradient applies well along the Gulf Coast on reservoirs of Oligocene and younger age—in other areas factors as high as 0.760 and as low as 0.420 are used. These values have been published and are usually well-known to experienced geologists.

A reservoir pressure of 2325 pounds amounts to 158 atmospheres ($2325 \div 14.7$); so there is 158 times as much gas in the reservoir as it would hold at atmospheric pressure. This statement, however, is not quite true because Boyle's Law does not work exactly at higher pressures—it was worked out at lower pressures and later research has indicated variance at high pressures. This amount is known as supercompressibility, and the factor is called the Z factor. If the composition or density of the gas is known, one can figure the Z factor for different pressures and temperatures. In the present case, the Z factor could be estimated for normal Gulf Coast gas at that depth to give a multiplier of 1.225. The Z factor results in an additive multiplier down to depths of around 10,000 feet, and with normal pressures, is greatest around 4000 feet.

Gas reserves are figured to atmospheric pressure of 14.7 pounds; but sometimes the gas is already dedicated under contract of sale at a higher pressure, such as 16.4 pounds. In such a case, the 16.4 is divided into the reservoir pressure, and a smaller quotient results. It is obvious that it is to the advantage of the gas pipe line to buy the gas on as high a pressure base as possible—on a 29.4-pound base only half as many cubic feet are paid for as on a 14.7-pound base. Gas pipe lines nearly always sell gas on a 14.7-pound base.

In addition to correcting for pressure and supercompressibility, correlation must be made for the reservoir temperature. Charles' Law states that as the temperature is increased, volume decreases in proportion to absolute temperatures. If bottom-hole temperature is known, this reduction in volume can be figured by direct application of Charles' Law to reduce the gas to the volume it would have at 60F, which is the standard temperature. If reservoir temperature is not known, it can be estimated from temperature-gradient curves for the area —such temperature gradients vary grossly from one province to another, but in any particular area are quite regular and are well-known. For the example lease, from curves available on this area, it is found that the reservoir temperature should be 170F, and by application of Charles' Law, 0.825 is arrived at as the temperature-correction factor.

Only the recovery factor (F in the formula) remains to complete the calculation. Many gas fields have been produced to exhaustion—some in recent enough times for complete production figures to be available. Recoveries run very high, and with proper location of wells, one could recover about all the gas in a water-drive reservoir. But, because of improper structural location of wells, lenticularity, and other irregularities, recoveries seldom run over 90 percent. On the Gulf Coast in water-drive fields, the factor of 85 percent is commonly used at this time.

In confined reservoirs where only gas expansion drive is available, it is usual to fix some abandonment pressure. Trunk-line carriers do not desire gas at a pressure of less than 500 to 750 pounds per square inch—as the saying goes, "it will not buck the line" at lower pressures. Gas at less than line pressure must be compressed before it can be sold, and compressing requires equipment and costs money. Depending on the outlet to which the gas is going, an abandonment pressure of 500 pounds or more is allowed for in fields where the pressure will decline. If one neglects supercompressibility change with pressure, the recovery factor is equal to the original-minus-abandonment-pressure difference divided by the original pressure.

For the example lease, a water-drive recovery factor of 85 percent is used. The calculation therefore is $36{,}310{,}912 \times 158 \times 1.225 \times 0.825 \times 0.85$, a total of 4,928,368,853 feet of recoverable gas. As gas is sold in 1000-cubic-foot units, this amount would be written as 4,928,368 mcf—and as reserves are usually estimated in millions of cubic feet, this amount would be written as 4928 mmcf. From production data, it is found that 227 million cubic feet have been produced, and that a reserve of 4701 million cubic feet is left.

The converting of gas reserves into dollars is the same as for oil, except possibly that it is more of a certainty. Gas is sold under long-term contracts, usually 10 to 20 years, at stipulated prices; for this reason the price does not fluctuate as greatly or as rapidly as the price of oil. It is easier to foresee what the gas price is to be in years ahead, and it is much more likely to remain at the present level than is oil. Also, gas deliveries are scheduled for years ahead, so it is easier to estimate over how long a period gas production will be extended.

If the future price and future deliveries of the well are not covered by contract, it is assumed that the rate of production and price will remain the same. A schedule of future income year by year is set up, with expected future expenses deducted. The costs of operating gas wells are usually much lower than costs for oil wells. The present value of each year's income is discounted back to present value; final salvage value is discounted; and these are all added together to give the total present worth of the property.

Many gas wells, particularly those in high-pressure reservoirs, produce a liquid called "condensate." This liquid was in the sand, but it was there as a vapor. It condenses into a liquid when brought to the lower pressure and temperature at the surface. The amount varies from less than 10 to more than 100 barrels per million cubic feet. If the reservoir is under water drive, the yield of condensate will remain substantially constant; but, if it is under gas-expansion drive, the yield will decline as the pressure drops.

In the example field, it is assumed that the yield is 5 barrels per million cubic feet of 54° API condensate. Since there is a water drive, it is further assumed that the yield will remain the same, and that the price will remain at $2.90.

As in the case of oil, the future sales price of this 21,690 barrels of distillate (4338 × 5) is discounted back to present value by using a 5-percent discount factor. This factor is added to the present value of the gas. The distillate is worth more if the gas is to be produced quickly than if it takes a long time, as time brings on a heavier discount factor.

CHECKING THE VALUE

The final result of the valuation study should be checked by the geologist by any and every means available to him. As stated above, he should know the average acre-foot recoveries from similar recoveries. If his reserve estimate is far out of line, he should know why.

He should know the average selling price of oil in the ground and of gas in the ground. This price he can constantly know by analyzing the sales of producing properties. For instance, oil has sold recently from $0.80 to $1.05 a barrel in the reservoir, and gas at 1 to 2½ cents per thousand. These figures often enable one to check the present-worth estimate because sales are often 60 to 70 percent of present worth.

Whenever decline curves can be constructed, they should always be used. The solution should be worked out by projecting the curve. The curve should come out in the proximity of the computed estimate—if it does not, another check should be made. If any material-balance equations can be solved, they should always be used—even though they give data only on the entire field, they often confirm or deny the conclusions.

The evaluator should always go on the property, physically inspect everything he can see, quiz the gauger who handles the lease, and get the latest production figures he has. In setting up a reserve estimate, the valuator says by implication that he expects the wells to produce for years and years—he must be certain they are not already beginning to fail.

CONCLUSION

Accurate valuation of oil-and-gas properties now depends entirely on a proper understanding of the conditions existing in the producing reservoir. Since one cannot go down in the reservoir, as one does in a mine, all conclusions must be based on inference, comparison, and experience.

Although an understanding of the fundamentals of production engineering is needed, it serves only as a background. The geologist who is familiar with all of the producing structures in the trend and who knows the geologic section in the wildcats is best equipped to analyze the production data from any one field. There is much more to outguessing Mother Nature than being able to reduce well performance to exact figures, or to analyze an electric log into precise millivolts and ohms.

Geology, being a study of the earth itself, involves its students in a consideration of the source of sediments, conditions of deposition, up- and downdip facies changes, lateral variations in thickness or character of reservoir rocks, and countless other kindred problems of sedimentology. Because of his training in these matters and his continued interest in them, the well-grounded subsurface geologist makes the most reliable evaluator.

Reprinted from *Subsurface Geologic Methods,* 1951, p. 792-809.

Part Eight

EXPLORATION PROGRAM

Chapter 41

EXPLORATION PLANNING

E. A. Wendlandt

This is a story of exploration. In it is traced the development of a full-scale exploration program that an imaginary company conducts in a hypothetical sedimentary basin in its search for petroleum. The story stresses the way a modern oil company might use the various geological and geophysical methods and techniques in an attack on a potential oil province. It stresses the fact that the driving force of an exploration program is geological thinking and that this thinking is the main tool utilized by an exploration-minded oil company.

THE AMERICAN PRODUCTION & EXPLORATION COMPANY AND ITS POLICIES

The American Production & Exploration Company, referred to in industrial circles as Amprex (fig. 41-1), has been operating successfully in the Gulf Coastal Plain, the Mid-continent area, and the Permian Basin area of West Texas and New Mexico, and like other oil companies exploring for oil today, it has found its costs of exploration and development rising alarmingly. The price Amprex receives for its crude and for its refined products is no longer commensurate with the profits of earlier years when the costs of finding and developing domestic oil were much less than they are today. Like some of its competitors, Amprex has invested heavily in foreign regions, and it has been successful in its search for oil reserves in several such areas. Fully aware of risks involved in foreign operations due to such possibilities as either expropriation or war, Amprex critically analyzes all its foreign investments and exploration efforts. A large percentage of its income is reinvested in domestic exploration.

Like any successful group of oil finders, Amprex's exploration team maintains an open mind on the petroleum possibilities of all sedimentary basins. In recalling the philosophy of Wallace E. Pratt, these geologists and geophysicists realize that the unkown is frequently confused with the unattractive; they guard against negative thinking resulting from too few facts, and, at the same time, they try to keep their viewpoints both optimistic and realistic. The geologists and geophysicists on the team accept the premise that oil is a very common substance in the sedimentary rocks of the world, and that it may have been formed wherever sediments have been laid down in a saline environment.

Amprex's management feels that the company should attempt to meet competition, not only in its marketing program but also in its exploration; therefore, most of the company's domestic exploration budget is assigned to the search for oil in those areas where industry is concentrating its activity. The management of the company is both far-sighted and aggressive and part of Amprex's exploration energy is budgeted to the search for oil in little-explored areas where the finding of a "sleeper" could be extremely important. They realize that the discovery of oil in such an area can result in considerable profits. Such a discovery might open the potential not of just one field but of an entire new petroleum province or basin which could add hundreds of millions of barrels of oil and trillions of cubic feet of gas to the reserves of the company.

Because of its far-sighted policies, Amprex is generally ahead of competition in having acquired large blocks of potentially productive acreage in frontier areas at a relatively small cost and in having developed geological and geophysical information that will control the exploration program of the area. It is aware of the geological and geophysical techniques that are best applied in the search for structural and stratigraphic traps of the basin, and it has acquired a general idea of where the most attractive structural and facies trends exist for the accumulation of oil. Its men are on the ground, finding and acquiring new prospects. It fully understands federal, state, and civic laws that govern the area. Politically, the company has brought new wealth to the area; and, since it has acted fairly and generously in its initial contacts with the people, it will have continuing benefit from the good will created. Through ownership of all of the acreage of individual fields, the company will be able to develop the fields more efficiently, and with proper well spacing, controlled rates of production, and good engineering practices, it will ultimately produce more oil with a smaller capital investment than it would in fields having a

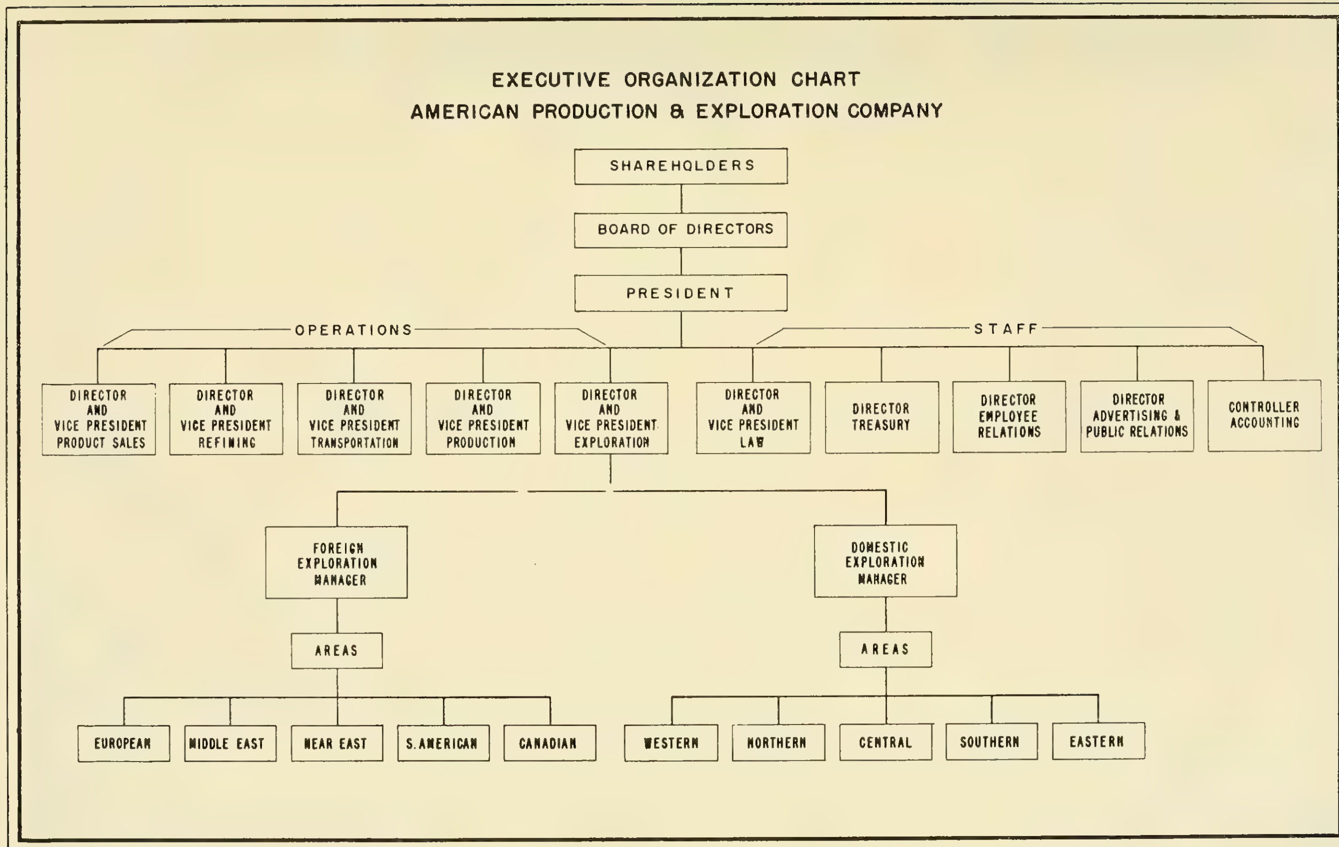


FIGURE 41-1. Executive organization chart of American Production and Exploration Company.

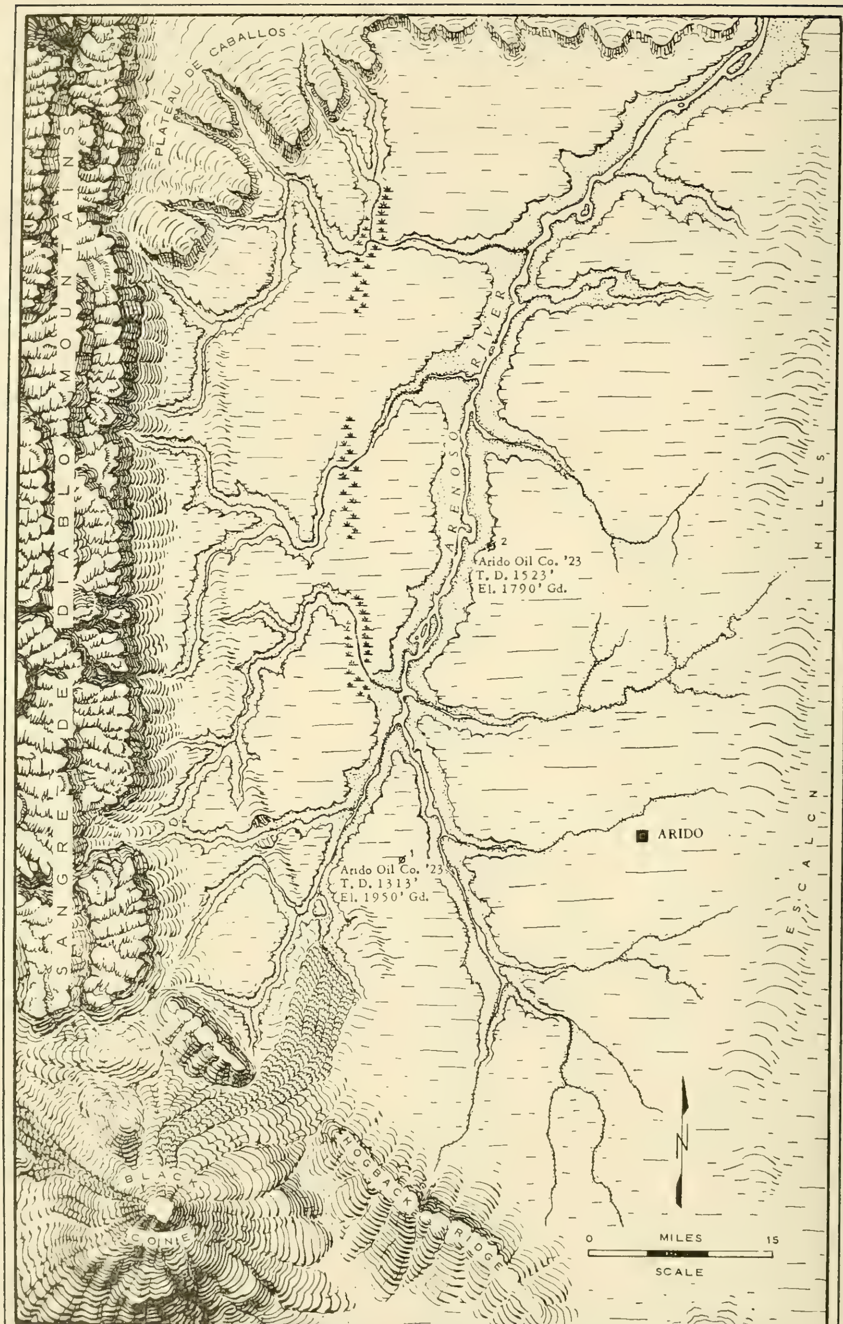


FIGURE 41-2. Physiographic diagram of Arenoso Basin.

diverse ownership of leases. Secondary recovery operations, where applicable, are more efficient where the field is controlled by one owner or operator.

Amprex recalls an outstanding example of progressive exploration, the Cuyama Valley of California, where a large lease block was tested by a wildcat well drilled in 1948. Approximately 300 million barrels of new oil was discovered by this wildcat drilled in an area that had been condemned for many years by some competitors. Valuable concessions in the Middle East, Near East, Indonesia, and South America follow the same pattern of large rewards resulting from optimistic thinking. It was with this objective that Amprex first began investigating a barren desert waste in the western part of the United States, an area known to the marginal farmers and ranchers as the Arenoso Valley or Basin (fig. 41-2).

THE ARENOSO BASIN—A POTENTIAL OIL-PRODUCING REGION

Little was known of the Arenoso Basin region when a geologist of Amprex's exploration group first visited the area. He wondered what lay beneath the nearly 5000 square miles of alluvial-covered lands which composed the floor of the basin. Early mapping by geologists of government agencies had indicated that the rocks exposed in the hills and mountains that bordered the basin to the southwest and west were composed of Paleozoic sediments. A fairly complete, although thin, Paleozoic sequence of carbonate and clastic sediments with many extrusive and intrusive igneous rocks was reported. However, there had been no detailed mapping of either facies or stratigraphy and the structural aspect of the area was very generalized. A discouraging fact relating to the basin was the presence of two wildcat tests drilled in 1923 by Arido Oil Company, which had reported "basement rock" at relatively shallow depths.

During the years subsequent to the drilling of these tests, probably many geologists had viewed the intrusive igneous outcrops and the shallow "basement tests" with pessimism and had condemned the Arenoso Basin area. Amprex's geologist, however, recalled the great oil fields of the Tampico region of Mexico and their close association with outcropping igneous intrusives, and at the same time, he considered the possibility that the two reported "basement tests" were abandoned in extrusive igneous rocks, perhaps late Tertiary or Recent lava flows, rather than basement rocks. He knew that, in the infancy of oil exploration, men untrained in geology often described the rocks encountered by the drill and, therefore, the rocks were sometimes improperly identified. Moreover, he was reluctant to condemn a basin of more than three million acres with only two shallow dry holes. With this initial optimistic thinking, Amprex began its attack on the Arenoso Basin.

INITIAL INVESTIGATIONS OF THE ARENOSO BASIN

Its interest aroused, Amprex's Exploration Department assigned two experienced geologists to investigate the region. Utilizing the company's geology library and its staff, the geologists made an intensive search for all available published and unpublished information pertaining not only to the Arenoso Basin but also to the surrounding area for hundreds of miles in order to develop the regional pattern of geology which might afford better understanding of local conditions. At the same time that the literature stage of investigation was initiated, the Exploration Department requested that Amprex's Law Department begin investigating the legal problems that would be inherent in operating in the Arenoso Basin. The Land Section of the Exploration Department was asked to make a land check of the area and ascertain what problems would confront them in acquisition of leases. The Scouting Section of the Exploration Department was instructed to search all sources for data relating to the area and, particuarly, if at all possible, to locate a set of cuttings and cores from the two wildcat wells. Federal and state geological surveys, universities and colleges, federal and state ground-water districts, and all other agencies that might have information pertaining to the area were contacted. All of this data gathering was conducted with a minimum of publicity.

As the available data were assembled from various sources, Amprex's two geologists, assisted by a staff of draftsmen and stenographers, began integrating this information into a summary of the regional geology. They constructed regional geological maps. A composite areal geologic map was compiled, utilizing both federal and state mapping. It had been determined that a few local areas had been mapped by graduate students working on thesis problems, and their maps were incorporated into the composite regional map. It was found that a federal agency had "flown" the area, and the aerial photographs were purchased. After a photographic mosaic was constructed from these air-photos, specialists trained in photogeology developed areal geologic and structural maps from studies of the photographs and other available data. From the few measured geologic sections exposed in the mountains, hills, and canyons of the region, Amprex's geologists constructed preliminary regional thickness and facies maps of the sedimentary rocks and made preliminary paleogeographic and paleogeologic interpretations.

After compiling and studying the available information, Amprex's geologists moved into the field and began reconnaissance geological studies of the surface outcrops. Utilizing the assistance of highly trained specialists of the company's Geologic Research Section, these geologists measured and described in detail geologic sections that outcropped in different parts of the hills and mountains surrounding the alluvial floor of the basin. These sections provided a key to the subsurface stratigraphy of the valley.

Perhaps the most significant result of the initial phase of investigation was the discovery that a set of cuttings from one of the two early wildcat wells was available for study. Fortunately, these samples had remained undisturbed in the storehouse of a university for more than thirty years. These cuttings and cores were studied by the company's geologists and paleontologists. A petrographer examined cuttings from the subsurface section referred to as "basement" by the operator, and described these igneous fragments as "hard, dark, fine-grained igneous rock composed of plagioclase feldspar, pyroxene, and fine, opaque ore minerals, with an occasional phenocryst of coarser pyroxene." This description, typical of extrusive basalts that were found in the Black Peak area to the south, convinced Amprex's geologists that this old wildcat had not encountered basement, but instead had been abandoned in extrusive igneous rock lying beneath a section of late Tertiary or Recent alluvial fill. It seemed reasonable to assume that a Paleozoic section lay beneath this old flow.

With this encouraging information, the company geologists contacted their management and presented the facts. Both the law and land groups of the company indicated that there were no serious problems in either operating or leasing which would deter exploration in the area. The preliminary regional thickness maps, although based on limited information, suggested that several of the Paleozoic formations were thickening toward the center of the Arenoso Basin. The regional facies maps supported this observation by indicating a progressive change from light-colored carbonates and coarse clastics typical of shelf facies to darker carbonates and fine-grained clastics suggestive of basin facies. Structural trends mapped in the outcropping formations plunged basinward and, therefore, could be expected to persist into the "deeper" parts of the Arenoso Basin. The photogeologists mapped several anomalous patterns in the alluvium which appeared to be reflections of structures at depth. Petrographers, studying the extrusive and intrusive igneous rocks of the area, concluded that the metamorphism of the sediments surrounding these areas was local and not regional. All of the facts seemed to suggest that the Arenoso Basin or Valley might be a Paleozoic sedimentary basin with potential source and reservoir rocks and that favorable structures offering possibilities for production occur within the basin.

RECONNAISSANCE EXPLORATORY PROGRAM

After the management group of Amprex's Exploration Department had reviewed and studied this information, they recommended to the Board of Directors of the company that additional money be budgeted to conduct an extensive reconnaissance geological and geophysical exploration program for further evaluation of the area.

BUDGET

American Production & Exploration Company
Reconnaissance Exploration Program (one year)
Arenoso Basin

STRATIGRAPHIC TEST WELLS		$ 575,000
2 deep tests, $425,000; 2 shallow tests, $150,000		
SEISMIC SURVEYS		900,000
18 crew months @ $50,000 per mo.		
GRAVITY SURVEYS		180,000
24 crew months @ $7,500 per mo.		
MAGNETIC SURVEYS		45,000
5,000 sq. miles @ $9.00 per sq. mi.		
LEASE PURCHASES		100,000
400,000 acres @ $0.25 bonus		
LEASE RENTALS		-
TEST WELL CONTRIBUTIONS		-
SALARIES AND EXPENSES		350,000
Geologic	$170,000	
Leasing	50,000	
Scouting	10,000	
Geophysics	75,000	
Research	25,000	
Administrative	20,000	
TOTAL		$2,150,000

FIGURE 41-3. Budget for reconnaissance exploration program.

The Board approved the recommendation of the Exploration Department and budgeted $2,150,000 for a one-year period of reconnaissance geological and geophysical investigations of the Arenoso Basin. The budget included $100,000 to be used in the acquisition of large blocks of acreage that carried long-lease terms, low bonuses, and cheap rentals. These early lease blocks would be acquired along trends or in areas that appeared most favorably located, based on the meager information available on the basin geology.

The Exploration Department management then designed a budget controlled by the total expenditure approved by the Board (fig. 41-3) and assigned personnel for the exploration program. To supplement the effort without penalizing other active areas of exploration, contract geophysical crews were utilized in surveying the basin. Key geological and geophysical personnel were taken from active exploration divisions of the company and assigned to this project. A separate organization was formed, acting independent of any division and reporting directly to the exploration management of the company (fig. 41-4).

During the ensuing year, an intense study was made of the Arenoso Basin. Field geologists utilizing air photos, plane tables, alidades, stadia rods, Brunton compasses, hand lenses, and hammers—the tools of their trade—inspected and mapped most of the outcropping rocks of the area. Large mobile units or trucks carrying personnel and the scientific instruments of the seismograph and the gravity meter traversed the accessible areas of the basin. The total intensity of the earth's magnetic field was mapped by an airborne magnetometer. Mobile drills were utilized to drill shot holes for the seismic units, and larger portable drilling rigs drilled stratigraphic tests in different areas of the basin. Photogeologists studied the air photos of the area, assisted the field geologists, and searched for anomalous patterns in the alluvial cover that might be suggestive of structure at depth. Specialists, including a petrographer, a paleontologist, and a structural geologist from the Geologic Research group, assisted the surface and subsurface geologists in accumulating and interpreting their basic data. The Civil Engineering Section, utilizing the services of contract agencies where necessary, began constructing base maps of the area. Landmen acquired leases from many of the large landowners, applications were filed for federal acreage, and titlemen examined the land ownership titles in the courthouses. The vanguard of the oil industry had invaded the Arenoso Basin!

In initiating this stage of exploration, the management of Amprex's exploration group decided on a program of slim-hole stratigraphic tests. There were several reasons for this immediate drilling program. First, with a large area to explore, it was important that the early exploration energy be devoted to areas with the more attractive sedimentary sections. Second, the seismologists stated that the seismic survey costs would be abnormally high. Based on an estimated cost of $50,000 to operate a seismic crew for a month, the annual expense of one seismic crew would absorb $600,000 of the budget. It was important, therefore, that the seismic effort be concentrated in the more attractive areas.

In order to determine the more attractive areas, four stratigraphic tests were drilled, each being located in a different part of the basin (fig. 41-5). The objective of these tests was not to explore a potential structure or stratigraphic trap for oil and/or gas, but rather to evaluate the sedimentary section. Of primary interest to the geologists at this stage of exploration was the thickness and character of the sedimentary section in the various parts of the basin. Each test provided basic information vital to both geological and geophysical exploration. From a careful study of the cores and cuttings recovered by each test, the paleontologist, the petrologist, and the petrographer determined the age, the lithology, and the environmental and depositonal history of the rocks encountered in the hole. By correlating this information with similar information obtained from studies of the outcropping rocks around the margins of the basin, the geologists were able to refine their subsurface thickness, structure, and facies maps. The geophysicist ran velocity logs and made density measurements to assist the seismologist and the gravity computers in interpretations of their data. Where basement was encountered, cores were taken and analyzed by the geophysicist for susceptibility and other magnetic properties. Various types of electrical surveys and gamma-ray and neutron logs aided in the interpretation of lithology, porosity, and formation fluids. A formation test was made opposite each permeable section; and subsurface fluids, where recovered, were forwarded to the Geochemical Section for analyses. Subsurface pressure measurements made during each formation test were studied to establish the regional pressure gradients and patterns for the potential reservoirs of the basin. In addition, temperature and continuous dip-meter surveys were made of each of the holes. Cuttings and cores from each stratigraphic test were examined closely for any possible oil staining, for one of the most encouraging facts that a geologist can establish in any area is the presence of oil and gas shows. From the geochemical analyses of the subsurface fluids, crude isosalinity maps were constructed. The subsurface waters were analyzed for the presence or trace of either crude oil or natural gas. The information obtained from these four stratigraphic tests was invaluable and, as a result, Amprex concentrated its early exploration and lease acquisitions in those parts of the basin offering the best potentialities.

For competitive reasons, each of these tests was drilled as a tight hole. No information was released to either competitors or the public, and the distribution of the basic data derived from these tests was restricted to key personnel of the Exploration Department.

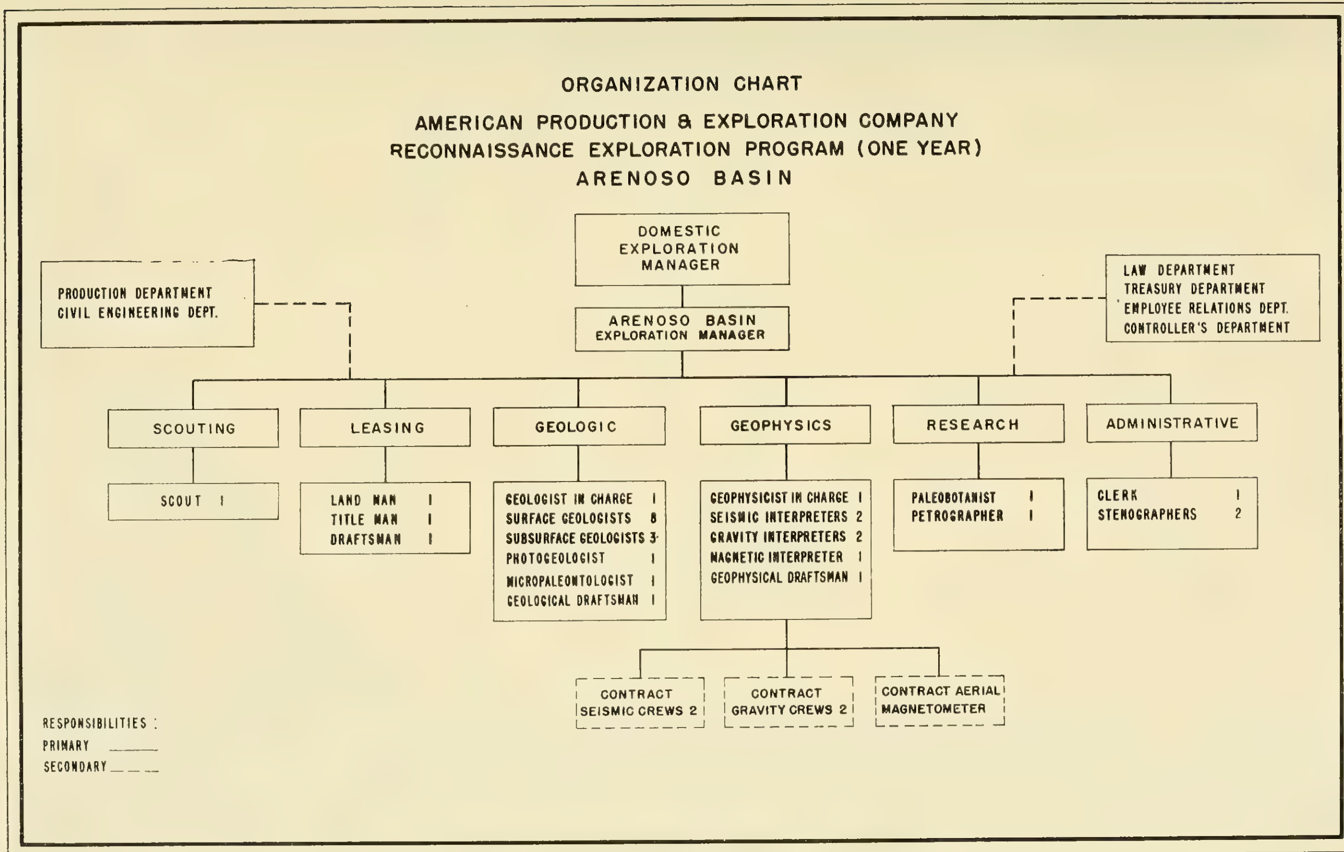


FIGURE 41-4. Organization chart for reconnaissance exploration program.

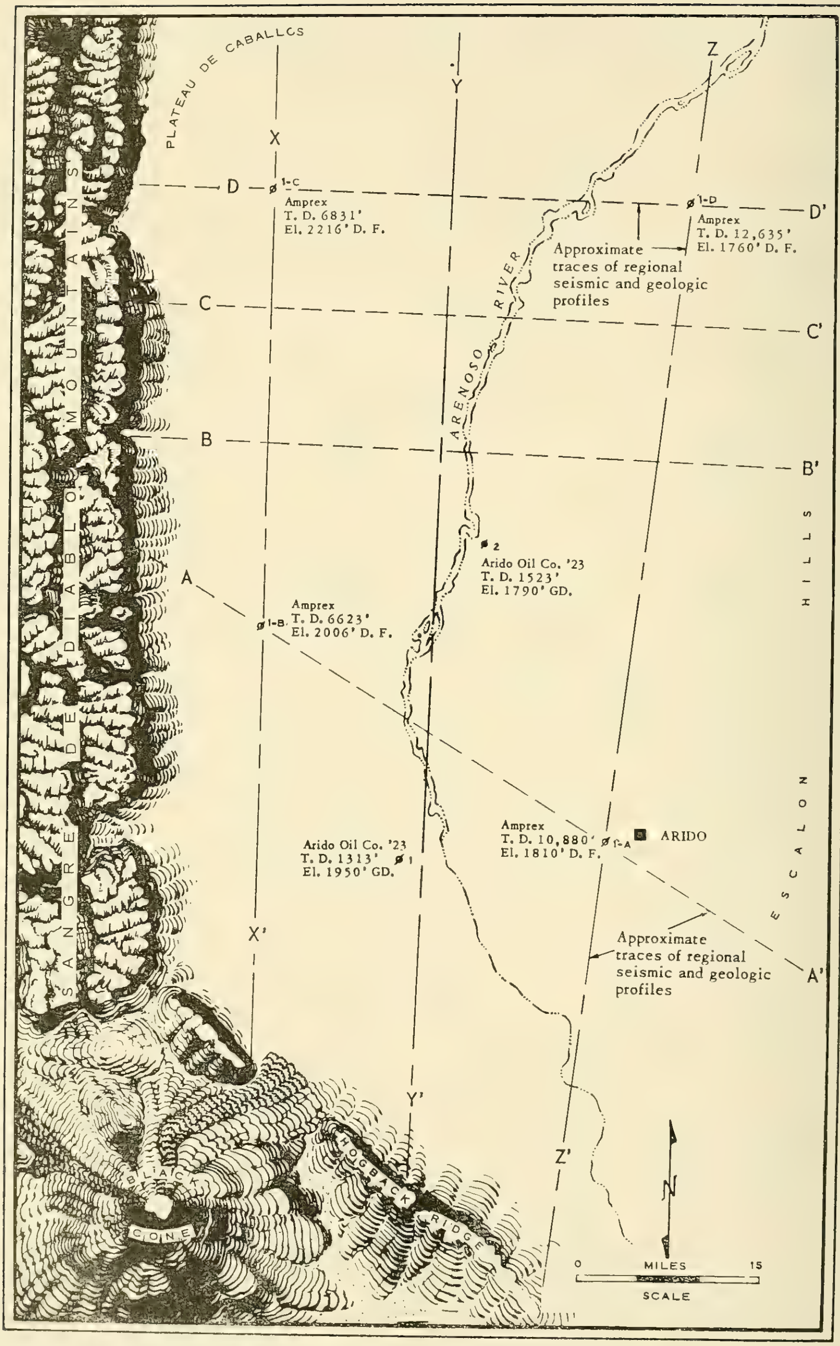


FIGURE 41-5. Regional sketch map of Arenoso Basin showing location of stratigraphic tests and approximate traces of seismic and geologic profiles.

Stratigraphic Tests

The first stratigraphic test, Amprex No. 1-A, located just west of the town of Arido, surprised even the most optimistic when it drilled through 1810 feet of alluvium into a carbonate section of young Permian sediments and was in marine Silurian clastics at 10,880 feet, its total depth. Paleontologists studied the samples and determined that an almost complete marine Paleozoic section had been encountered. Permeable sands and porous dolomites in the Pennsylvanian section and fractured dolomites and cherts of the Devonian were potential reservoir rocks. Dark brown, gray, and black sands, silts, shales, and dark limestones distributed throughout the Paleozoic column were potential source rocks. Faint, although positive, oil staining was noted in cores from several of the formations, and gas shows were recorded by the mud-logging unit while drilling through a clastic section of the Pennsylvanian. Formation fluids from all of the porous zones carried high salinities, indicating that, at least in this basin position, the reservoirs had not been flushed by meteoric waters. Minute quantities of hydrocarbon gases associated with several of the formation waters were indicated by geochemical analyses. These facts were very encouraging.

Moving approximately 30 miles to the northwest to a location 10 miles east of the eastern scarp of the Sangre de Diablo Mountains, the Amprex No. 1-B was drilled as the second stratigraphic test. The Paleozoic section penetrated was lithologically similar to the outcrop section but nearly twice as thick as that in the mountains to the west. The Paleozoic facies encountered in Amprex's No. 1-B were quite different from the basin facies of dark limestones and fine clastics encountered in Amprex's No. 1-A; the sediments of the No. 1-B were mainly light-colored carbonates and coarser clastics suggestive of a shelf or platform environment. Well-developed zones of porosity in dolomites and highly permeable sand sections characterized the Permian, Pennsylvanian, and pre-Pennsylvanian sediments. The subsurface waters recovered from formation tests were not as saline as waters from equivalent formations of the No. 1-A. Formation waters from the shallow Permian section were brackish to fresh, suggesting that meteoric waters had, at least partially, flushed subsurface areas of these rocks at this basin position. This would not necessarily preclude the possibility of encountering closed traps where oil and/or gas had been trapped prior to this flushing action. No shows of oil or gas were noted in the cuttings or cores from the No. 1-B test or by the mud-logging unit. A granitic basement was encountered at 6600 feet.

Amprex drilled its third stratigraphic test, the No. 1-C, about 35 miles north at a location at the foot of the Plateau de Caballos, where granitic basement rocks were encountered at 6809 feet. Its regional structural position was approximately the same as that of Amprex's No. 1-B. The thickness and facies of each of the formations were very similar to those of the No. 1-B and those of the outcrop section in the Sangre de Diablos to the west. Analyses of the formation waters again suggested some flushing action in the shallow formations, although the deeper pre-Pennsylvanian rocks carried waters with high salinities. Perhaps the most encouraging of all the factual data derived from the drilling of this test was the presence of possible reef or near-reef facies in a Devonian and Silurian dolomite section which carried faint oil staining in cores and cuttings. A drill-stem test of this interval indicated excellent porosity and permeability; and although it flowed water, there was a rainbow of oil on the salt water. Amprex's geologists were encouraged, for it seemed quite possible that this location might be near the edge of an oil accumulation.

After abandoning the No. 1-C, Amprex moved 35 miles east in the northeastern part of the basin near the northern end of the Excalon Hills and drilled its fourth stratigraphic test, the No. 1-D. This test actually proved the existence of a thick section of Carboniferous rocks in the Arenoso Basin, penetrating more than 7000 feet of Pennsylvanian sands, shales, and dark limestones beneath a predominantly carbonate Permian section. At its total depth, 12,635 feet, this test was in Mississippian rocks. Numerous shows of oil and gas were recorded by the mud logger and noted in the cuttings and cores, but most of the sands and limestones were impermeable. The top of the Mississippian in this test proved to be 8000 feet structurally lower than in the No. 1-C and 4000 feet lower than in the No. 1-A, Amprex's first test located more than 50 miles to the south.

Several significant features of the geology of the Arenoso Basin were disclosed by the drilling of the test wells. The Pennsylvanian section was found to thicken toward the axis of the basin and to exhibit a marked change of facies. The carbonate rocks which characterized the outcropping Pennsylvanian sediments in the Sangre de Diablos and the sections penetrated in both the No. 1-B and No. 1-C test wells did not exceed 600 feet in thickness; lithologic and faunal aspects of these carbonates indicated shelf deposition. The thick section of Pennsylvanian clastics near the basin axis, however, exhibited characteristics of typical basinal deposits, including laminate bedding, restricted planktonic faunas, and dark shales with disseminated pyrite. This change in facies denoting distinct environmental conditions in the Arenoso Basin during Pennsylvanian times, together with the westward convergence of the section, provided a basis for reasoning that a structural hinge belt existed along the strike of the region. Amprex's geologists realized that such a hinge belt is usually a flexure or fault zone which marks the position where the basin actually begins to break or bend down to accommodate an increased thickness of sediments. They knew that such flexures characterize many of the major oil-producing basins of the world, providing favorable structures and reservoir conditions to form major producing trends. They reasoned that a hinge belt should be present in the Arenoso Basin in the zone of thickening where the Pennsylvanian facies changed from shelf to basin deposits. They set out to locate flexures, fault zones, or other types of aligned structures which might help them to localize the hinge belt within the structural framework of the basin.

Geological and Geophysical Operations

Utilizing the subsurface information obtained from the four stratigraphic tests, Amprex's geologists revised their regional structure, thickness, and facies maps. While the tests were being drilled, the company revised its seismic program in order to concentrate the initial seismic energy in the most attractive areas of the basin. Two seismic crews were contracted from Trans-World Geophysical Company, one of the contract companies which had shown progressive action not only in instrumentation and seismic techniques, but also in interpretation of geophysical data. Company geophysicists were assigned to work with the contract group in both the field work and the interpretations. Two gravity-meter crews were contracted from Geo-Service Exploration Company to make a gravity survey, and at the same time, a contract was made with Airborne Magnetics, Incorporated, to make an airborne magnetic survey of the basin.

The initial seismic work was of a regional nature and was designed to distinguish the major structural features of the valley. A grid of west-east and north-south seismic profiles (fig. 41-5) was programmed with several of the lines being located to pass through the proposed locations of the stratigraphic tests. "Shooting" along the dip profiles, lines A-A′, B-B′, C-C′, and D-D′ were completed prior to the three north-south or strike profiles. The four stratigraphic test wells had been drilled before seismic work was completed along the north-south lines; and, as mentioned previously, seismic velocities had been measured in each of the holes. Stratigraphic information and velocity measurements obtained from the test wells provided the seismologist with accurate information with which to interpret seismic records and to correlate properly reflections along the profile lines.

While the geophysical work progressed, Amprex's geological staff, in addition to supervising the drilling of the stratigraphic tests, attempted to improve their understanding of surface and subsurface geological relationships. A reconnaissance geological map of the basin was prepared by four teams of surface geologists who had been assigned different areas of the basin to map. Research specialists, including macro- and micro-paleontologists, petrographers, structural geologists, and photogeologists, advised the surface men on special problems and helped to unravel some of the complex features encountered in mapping. They also made porosity and permeability measurements and examined various facies for evidences as to their environments of deposition. From the various types of information obtained, it was possible for the exploration

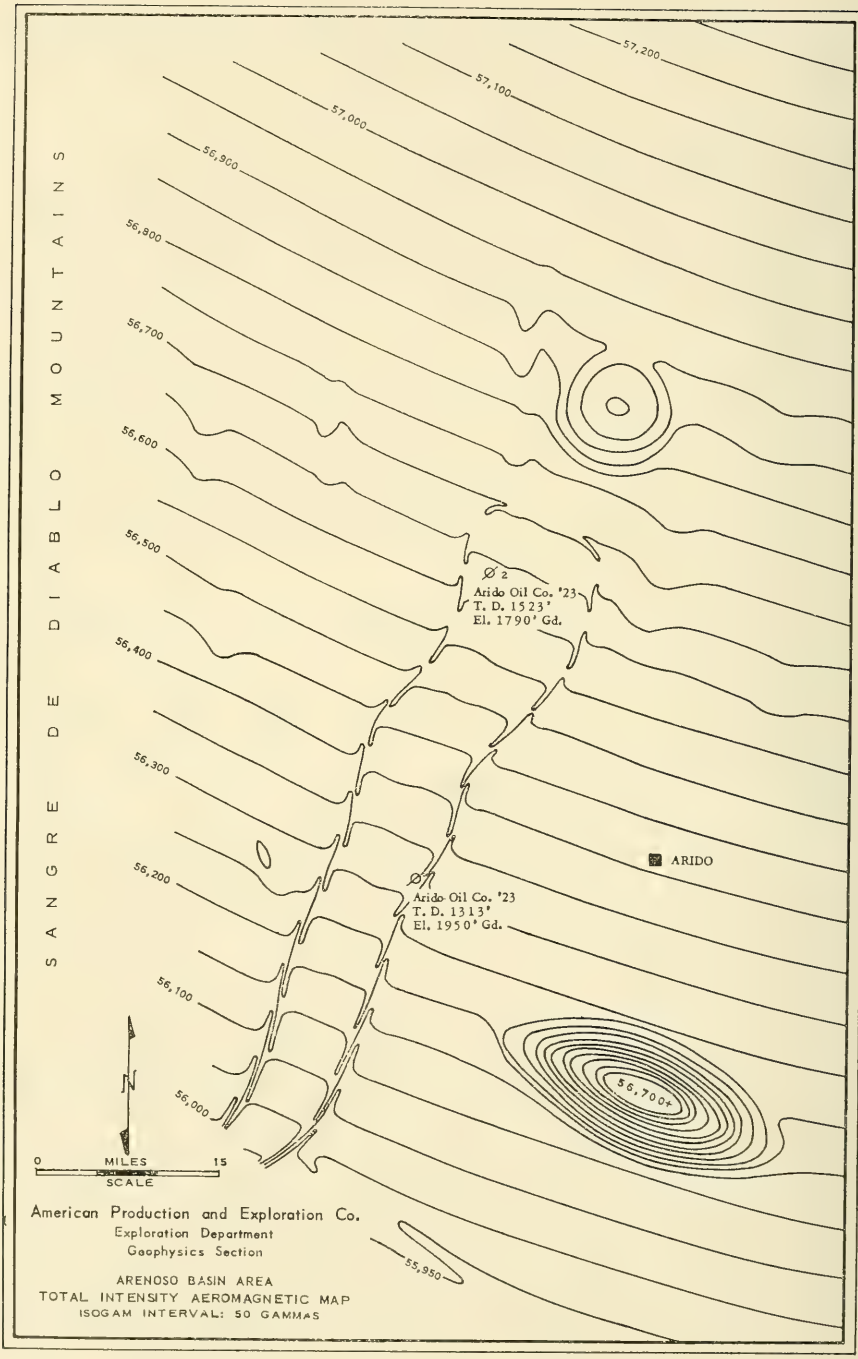


FIGURE 41-6. Generalized total intensity aeromagnetic map.

team to recognize critical sedimentary units and to prepare preliminary subsurface maps showing their concepts of thicknesses and facies.

Gradually, the basic information accumulated. Surface geologists completed their areal geologic maps of the basin and the surrounding hills and mountains. The airborne magnetic survey was completed and different types of residual and derivative maps were prepared from the basic magnetic profiles. The two gravity crews working in different areas, respectively, finally met near the central part of the basin and "tied" their gravity values to create a composite survey of the basin. From these original gravity data, residual maps were prepared to assist in the interpretation of the data. Working with the seismologists, the geologists prepared regional cross sections from the seismic profiles.

From a study of the airborne magnetometer data (fig. 41-6) and the subsurface control of the four stratigraphic tests, the geophysicists and geologists were able to construct a topographic map that depicted the general configuration and depth of the basement surface. From detailed study of residual maps of the magnetic data, several anomalous areas and trends were noted that suggested structural anomalies in the basement rocks. Several probable fault zones and two possible anticlinal trends were rather poorly defined by the magnetic data.

Amprex's geophysicists considered the gravity meter to be one of the most useful tools in reconnaissance exploration. They had found it more definitive than the magnetometer in locating structures that result from deformation of the sediments because gravity anomalies are not necessarily dependent on relief of the basement surface. Also, the density of control is usually greater for gravity data, and corrections which are applied to the raw data are, as a rule, more precise than those applied to the magnetic data. Figure 41-7 is a generalized copy of Amprex's Bouguer gravity map of the Arenoso Basin showing results of measurements at almost 15,000 stations, an average density of three stations per square mile. Its construction involved corrections for elevation, latitude, and irregularities of terrain. It shows the resultant effects of both regional and local structures. While the major anomalies are readily apparent, some local structural effects are obscured by large regional effects, particularly where the local structural strike parallels the strike of the regional gravity contours. In such places the only effect is a slight widening or narrowing of the contours. In an effort to make these anomalies more apparent and easily localized, Amprex's gravity interpreters prepared a residual map by estimating the regional effect and subtracting it from the total effect. To the extent that the regional effect is correctly estimated, the resulting residual map is a representation of the local effect (fig. 41-8). Various techniques of estimating the regional effect were applied. A common one utilized profiles showing the corrected, or Bouguer, gravity values, with the regional profile sketched in by eye to give a smooth curve approximating the Bouguer curve. They also used mathematical techniques for computing a regional effect from the observed values, although they realized

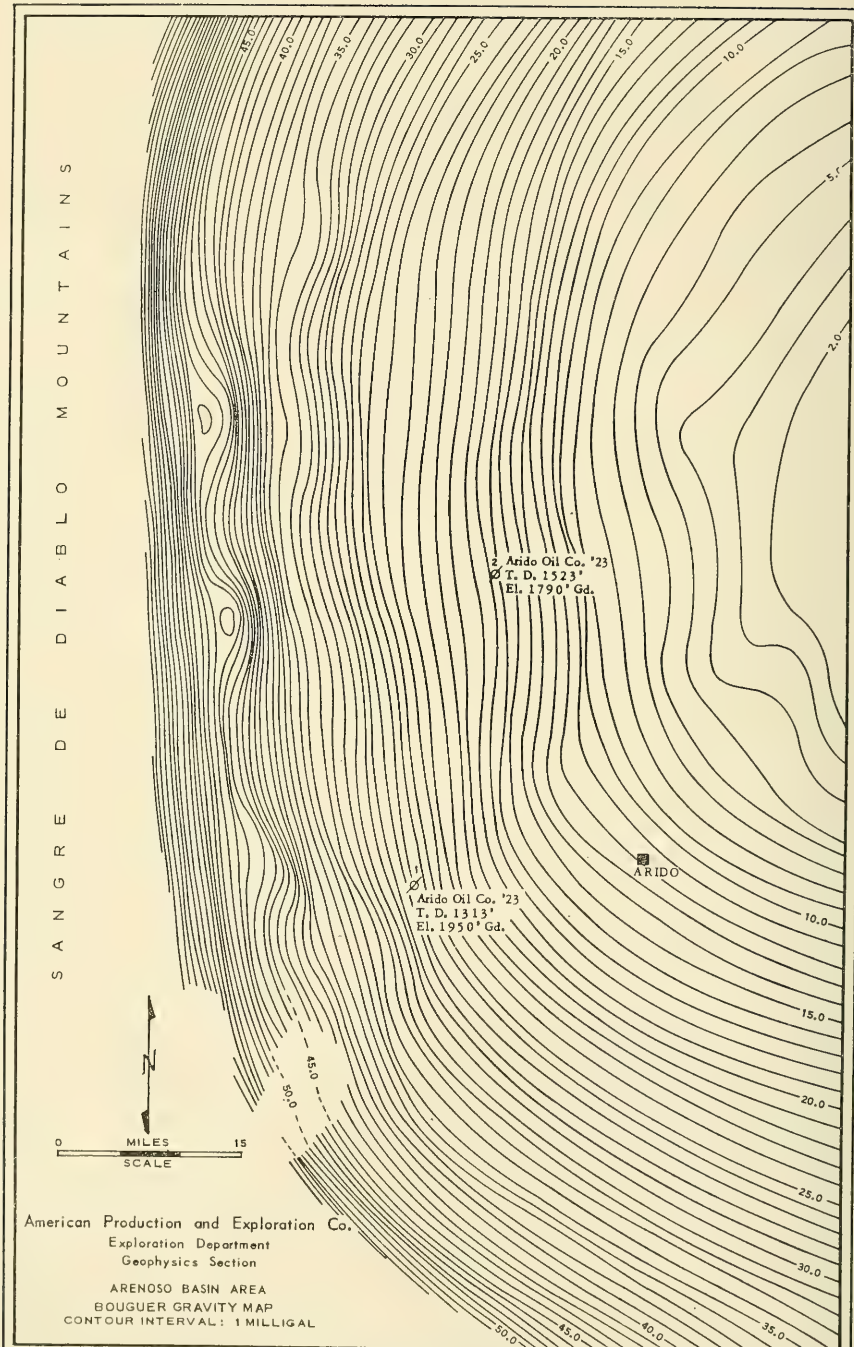


FIGURE 41-7. Generalized Bouguer gravity map.

that all such techniques are merely objective methods of drawing smooth regional curves and have no physical superiority to the subjective curves drawn by eye. One popular variation of the mathematical technique which they sometimes used was the derivative method, which combines the steps of computing a smooth curve and subtracting it from the observed values.

Amprex's geophysicists realized that all techniques employed to depict areas of anomalous rates of change of gravity, thus emphasizing local anomalies, can be useful tools if interpreted by experienced men. They were aware of the difficulties of interpreting gravity data in areas such as the western margin of the Arenoso Basin, where the basement rocks are shallow, and in other parts of the basin where the basement was considered to be of a heterogeneous composition. They knew from experience that when the composition of the basement varies, it is difficult to determine which anomalies are due to intra-basement density contrasts and which are due to structure in the sediments overlying the basement surface.

From studies of the gravity and magnetic surveys of the Arenoso Basin, Amprex's geophysicists defined many anomalous areas and trends. Perhaps most important was that the total effect of the gravity data provided them with a general outline of a basin of maximum sedimentary fill. Steep gradients in gravity data and irregularities in magnetic data indicated two anomalous trends in the west-central part of the basin that might be indicative of strong fault zones having large displacements downthrown to the east. The most westerly of these two trends could be interpreted as a major hinge belt within the basin. Just west of this feature was a trend of gravity maximum anomalies that indicated possible anticlinal structures. Other gravity anomalies were outlined and added to the prospect files for further investigation.

Most of the Paleozoic rocks of the basin were covered by a relatively thick section of alluvium, and Amprex found that its usual methods of surface geological exploration were in many places ineffective. Broad alluvium-covered areas within the basin, such as flood plains and alluvial fans, were both difficult and expensive to explore with conventional methods.

However, the photogeologists found such areas to be ideally adapted for certain types of their studies, for they knew from experience in other areas that in alluvial regions of low relief, even very small structural uplifts and downwarps may disturb stream adjustment and cause local abnormalities to develop in the normal regional drainage pattern. From their studies of the airphotos of the area, they discovered many anomalies, and each of these leads was checked at a later stage of exploration by either the core drill or the seismograph, or both.

Utilizing all of the available information, Amprex's geologists and geophysicists combined their talents and constructed a series of regional geologic cross sections, both dip and strike, which depicted the regional stratigraphy and

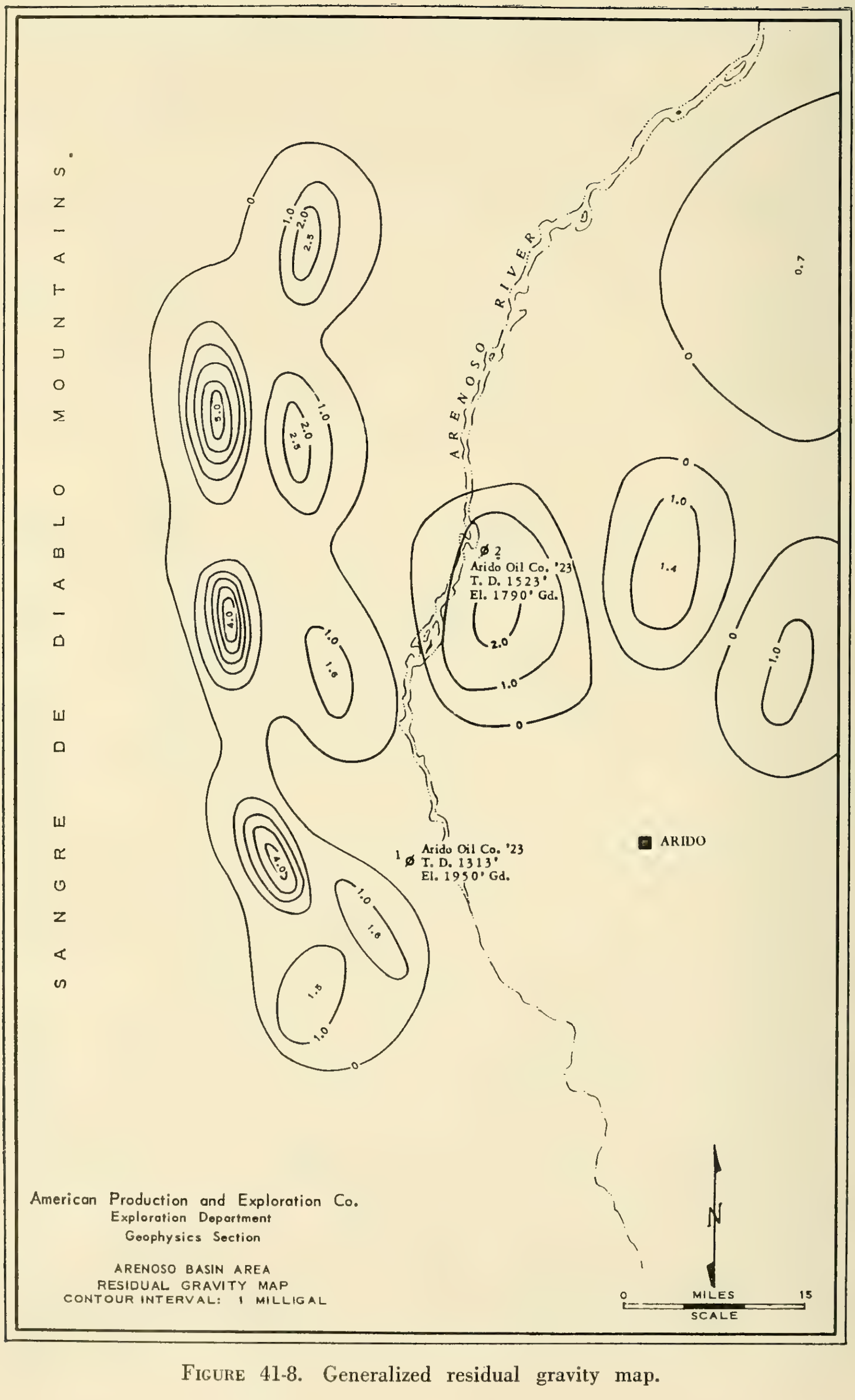


FIGURE 41-8. Generalized residual gravity map.

structure of the basin. Figures 41-9 and 41-10 show very generalized copies of two dip sections, D-D′ and A-A′, respectively, that traverse the basin from west to east, and Figure 41-11 shows a copy of a south-north section, Z-Z′. Figure 41-12 is a copy of the northernmost of the regional seismic profiles. D-D′. The trend of the cross sections and of the regional seismic profile is indicated in Figure 41-5. By utilizing these sections and the geological and geophysical maps, it was possible to determine the approximate position within the basin of the trends of the most attractive facies, regional trends of anticlinal and fault structures, the most likely basin position for the growth of reefs in various stratigraphic units, and the approximate positions of the major hinge belts. Amprex's exploration management considered that the cross sections, the regional structure maps, the regional thickness maps, and the regional facies maps were the end products of this phase of exploration. In addition to completing the regional picture, the geological and geophysical surveys found many structural and stratigraphic areas that would be investigated by more detailed work in the event Amprex's management decided to continue exploring the basin. Figure 41-13 is a generalized copy of a map showing hypothetical contours of the basement surface of the basin. These contours were based upon all of the geological and geophysical information developed to date.

Approximately a year had elapsed since Amprex had initiated its reconnaissance stage of exploration. More than two million dollars had been expended in stratigraphic drilling, geological work, geophysical surveys, acreage acquisitions, and work allied to this program. When management had approved this original expenditure, it was aware that this was a considerable risk, for this relatively large sum of money was committed even though the results of the reconnaissance exploration might indicate that the area appeared unfavorable, and all exploration would be discontinued. Leases that had been acquired would be dropped, and money expended on this project would be charged against company income.

Although geologists and geophysicists had been studying and interpreting information as it accumulated, this was the real period of interpretation. Additional subsurface geologists were added to the original staff, and the subsurface data were reworked in order to investigate all possibilities of interpretations. Experienced geologists and geophysicists familiar with the occurrences of oil in different parts of the world were best qualified to interpret the geological and geophysical data, for at this stage of exploration, most conclusions were empirical. It was essential that Amprex expend the right type of exploration in the most attractive areas.

Advanced Exploration Program

The management of Amprex's Exploration Department examined the available information and studied the recommendations of the key geologists and

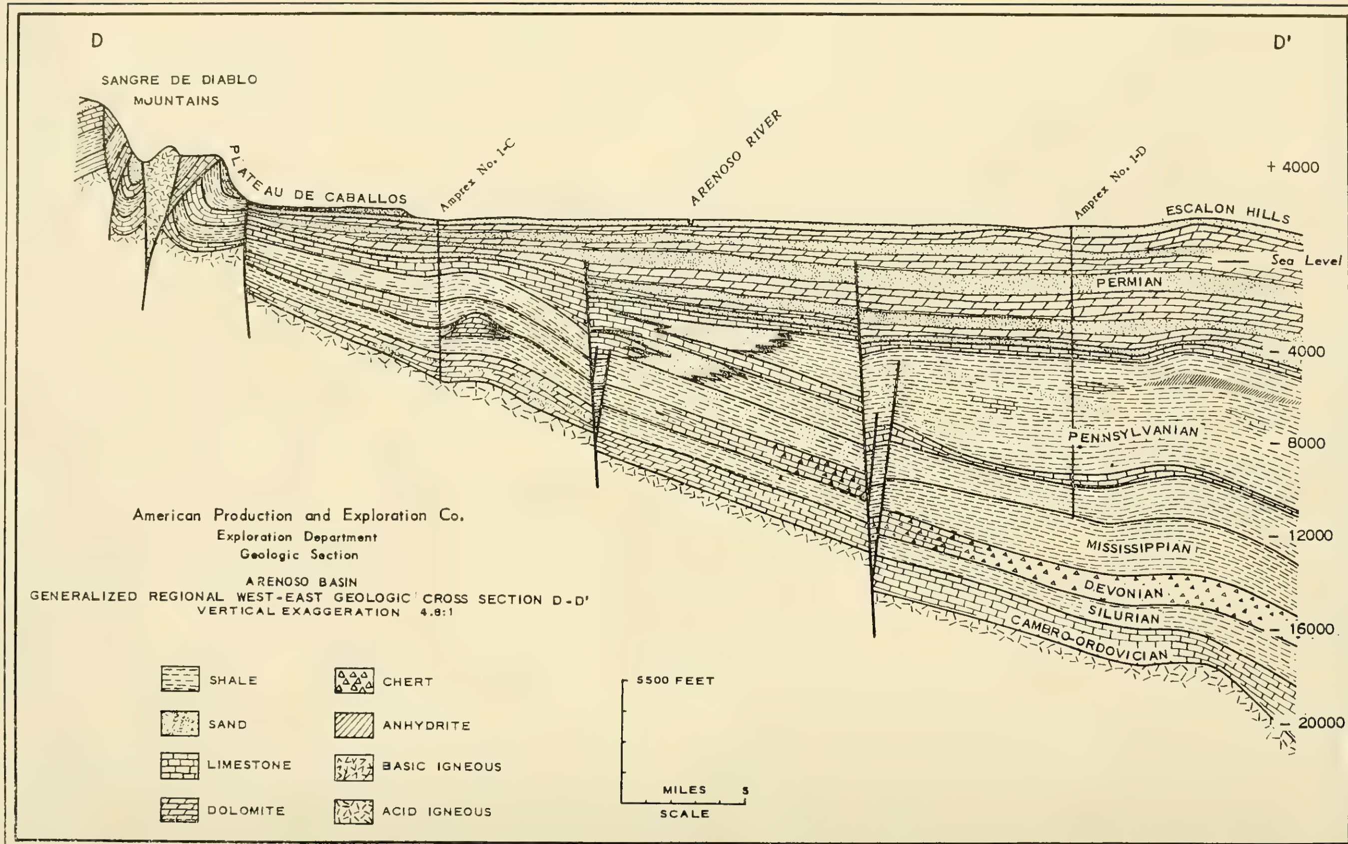


FIGURE 41-9. Generalized regional dip geologic cross section of Arenoso Basin. (See FIGURE 41-5 for location.)

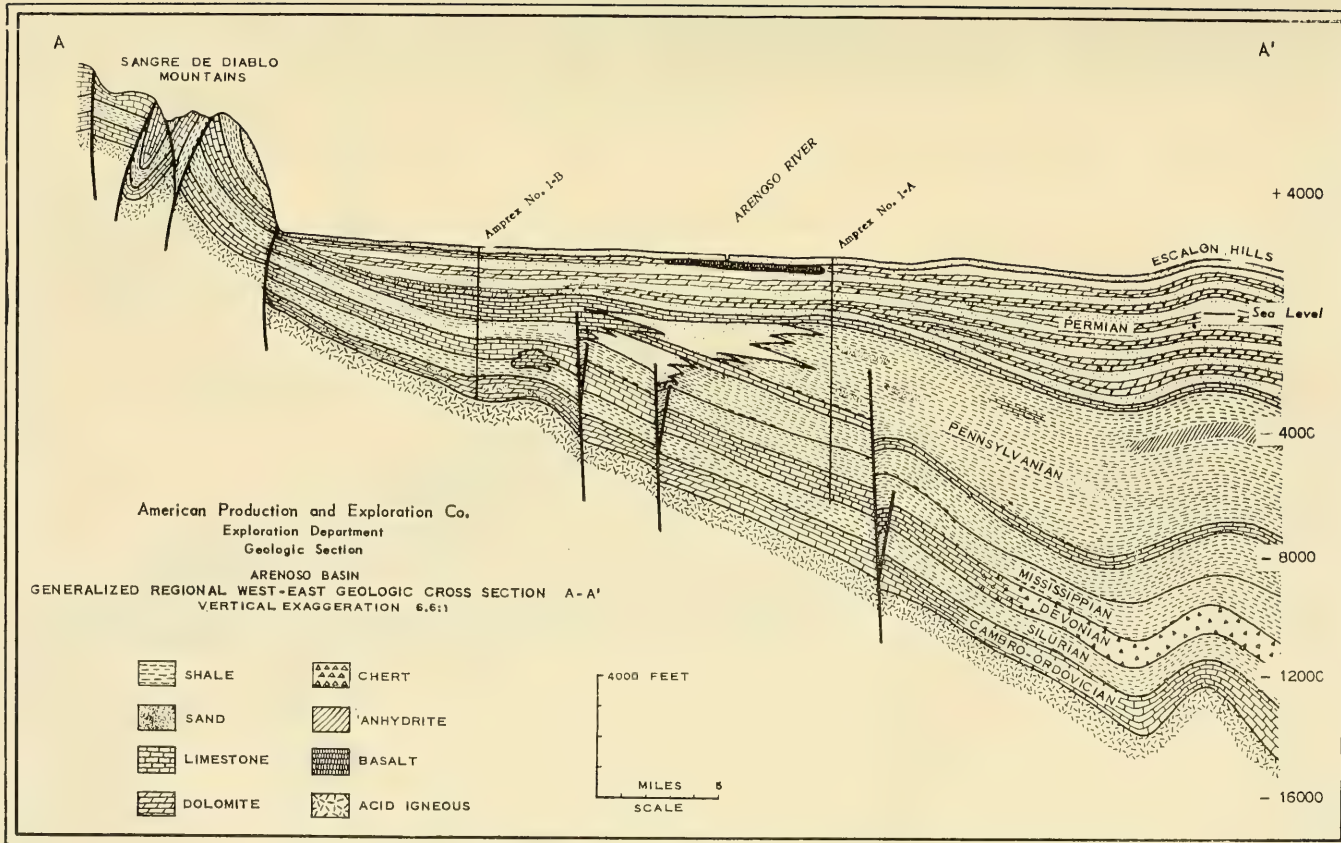


FIGURE 41-10. Generalized regional dip geologic cross section of Arenoso Basin. (See FIGURE 41-5 for location.)

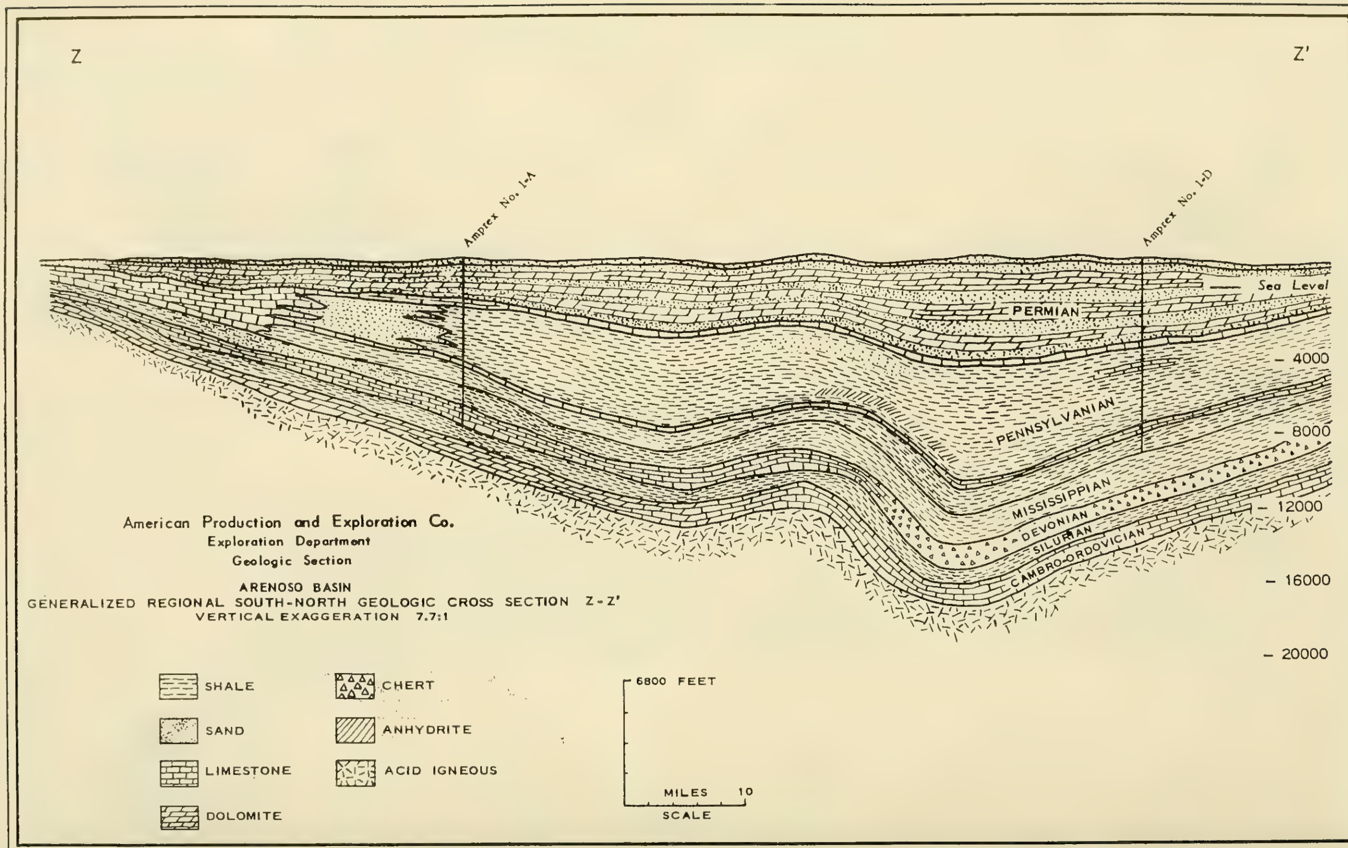


FIGURE 41-11. Generalized regional strike geologic cross section of Arenoso Basin. (See FIGURE 41-5 for location.)

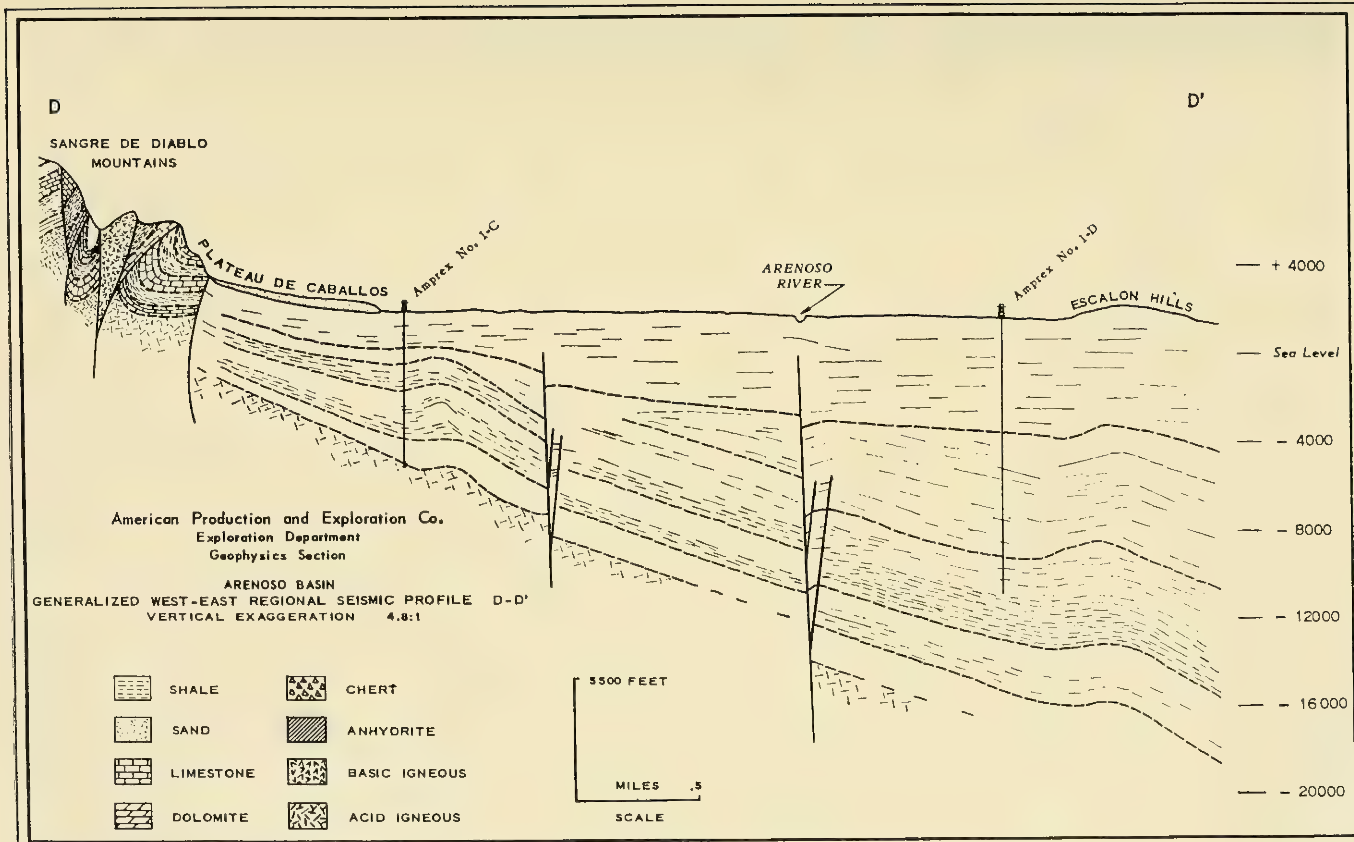


FIGURE 41-12. Regional seismic dip profile of Arenoso Basin. (See FIGURE 41-5 for location.)

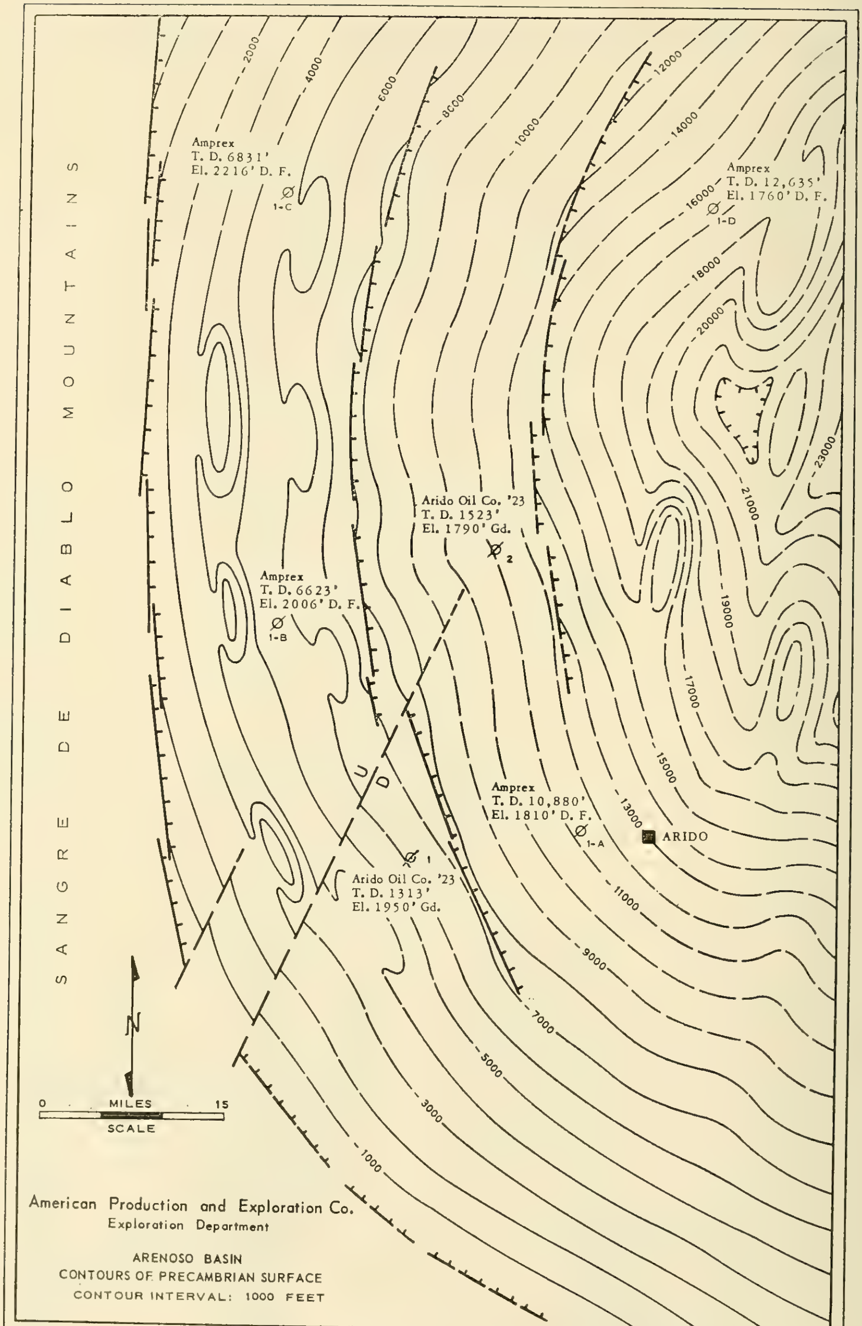


FIGURE 41-13. Precambrian contours inferred from geophysical and geological data.

geophysicists who had interpreted the work. They reached an optimistic conclusion on the petroleum possibilities of the Arenoso Basin because the facts and the hypotheses indicated that oil may have formed in the sediments within the basin and accumulated in structural and stratigraphic traps. It seemed to them that all of the factors required of an oil-producing area were present.

After preparing a concise summary of the facts and recommendations, Amprex's exploration group presented a formal review of these data to the Board of Directors of the company. They recommended that the company budget $5,450,000 toward a two-year program of detailed exploration, leasing, and wildcatting in the search for oil and/or gas in the Arenoso Basin. The Board approved this expenditure and the Exploration Department immediately began organizing a program under this new budget. Figure 41-14 is a summary of this budget revision, and Figure 41-15 shows the organization that was assigned to this program.

The tempo of exploration changed! The company had made a commitment to spend a probable minimum of eight million dollars in the basin.

The first action under this new program was taken by the Land Section of the Exploration Department, whose primary duty was the acquisition of acreage on the prospects or leads outlined by the geologists and geophysicists. During the reconnaissance stage of exploration, many leads suggested that an oil or gas field might be found by drilling in a certain area, had been developed. A good lead was the fact that shows of oil and gas were noted in the Amprex No. 1-C stratigraphic test. Many others had been found, including shallow occurrences of oil, gas, and mineralized water in some seismic shot holes and in water wells, although no actual surface indications of oil or gas, such as oil seeps or gas seeps, had been located. Anomalous data noted on some of the regional seismic profiles, such as reversal of dip, steep dips, or absences of reflections were also considered as leads, as were many gravity and magnetic anomalies. Photogeologists, subsurface geologists, and the field geologists submitted prospects for consideration. These leads were usually thoroughly investigated by detailed geologic and geophysical methods. In active oil-producing areas where competition is intense and the price of acquiring leases is unusually high, Amprex would usually try to evaluate prospects or leads before acquiring acreage. However, in the Arenoso Basin, leases could be acquired at reasonable costs, because the area had long been considered unattractive. Amprex realized that once it initiated a concentrated exploration program, and particularly a drilling program, competitors, through their scouting organizations, would learn of such plans and begin an active leasing campaign. As a result, Amprex decided to lease as completely as possible all of the leads or prospects that were developed by the earlier exploration. Entire facies and structural trends were partially covered through the acquisition of large lease

BUDGET

American Production & Exploration Company
Detailed Exploration Program (two years)
Arenoso Basin

WILDCAT WELLS		$ 530,000
5,000' well @ $130,000		
6,800' well @ 182,000		
8,000' well @ 218,000		
CORE DRILLING		360,000
24 crew months @ $15,000		
SEISMIC SURVEYS		2,400,000
48 crew months @ $50,000		
GRAVITY SURVEYS		180,000
24 crew months @ $7,500		
LEASE PURCHASES		900,000
600,000 acres @ $1.25 bonus, $0.25 commission		
LEASE RENTALS		130,000
400,000 acres @ $0.10 for 2 years 200,000 acres @ $0.25 for 1 year		
TEST WELL CONTRIBUTIONS		
SALARIES AND EXPENSES		950,000
Geologic	$400,000	
Leasing	200,000	
Scouting	20,000	
Geophysics	200,000	
Research	60,000	
Administrative	70,000	
	TOTAL	$5,450,000

FIGURE 41-14. Budget for detailed exploration program.

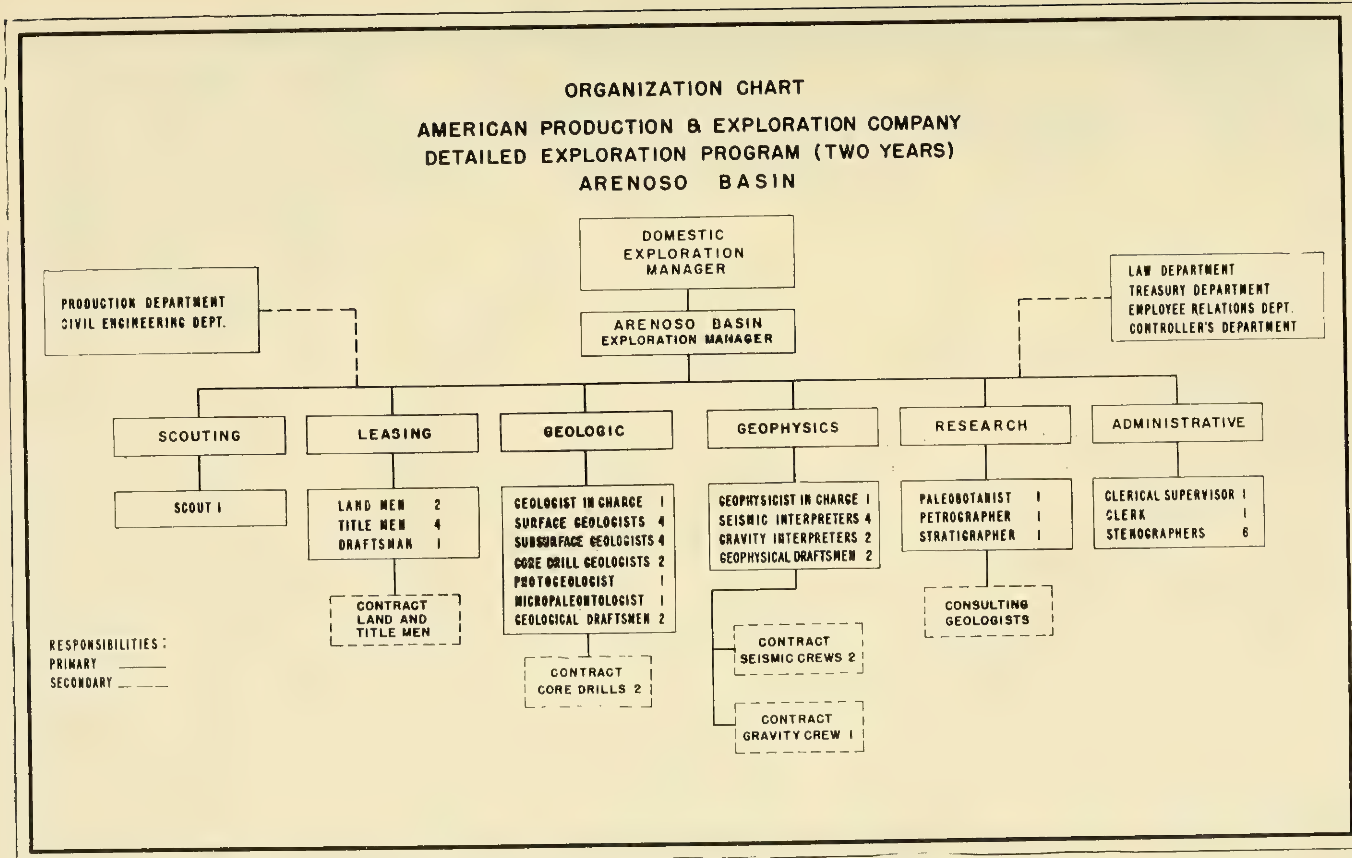


FIGURE 41-15. Organization chart for detailed exploration program.

blocks. A liberal buying outline was used in each of the prospects, for a lead may be located several miles from the center of the final prospect.

In order to acquire the hundreds of thousands of lease acres as quickly as possible, Amprex's Land Section utilized a staff of landmen, titlemen, and contract lease brokers. After receiving from the exploration manager the outlines of the areas or prospects to be leased, the landmen and titlemen checked land records in the courthouses to determine mineral ownerships. Company landmen and contract brokers then contacted the landowners and attempted to acquire oil and gas leases on the acreage within the buying outlines. Amprex's management of exploration had authorized a top lease bonus and rental price which the landmen were not to exceed. Because so little was known of the possibilities of the basin at this time and because the odds against discovering oil were so great in this frontier area, the cost per acre was relatively inexpensive, although the bonus, rental, and royalty were considered fair to the landowners. Amprex realized that these initial contacts with the owners were extremely important, since the good will acquired through fair trading would be one of the company's most valuable assets in future operations in the area.

Coincident with the leasing program, Amprex's management of exploration initiated its program of detailed exploration. With a much larger force to be used in this stage of attack, management very carefully planned and organized this phase of operations. Both old and new exploration tools were used. Detailed rather than regional surveys were conducted with the seismograph and the gravity meter. The core drill was utilized in mapping the structure and stratigraphy of the shallow subsurface. Field geologists began mapping in detail some of the anomalous areas they noted in their reconnaissance surveys.

Because most of the basin was covered with alluvium, the seismograph and the core drill were the most useful tools in the definition of structural and stratigraphic traps. During the reconnaissance phase of exploration, the seismograph was utilized primarily in running seismic profiles in the search for regional structural and stratigraphic features. Now the seismograph was used chiefly for locating and defining local structural and stratigraphic anomalies. It was mapping anticlines, foothill folds, reefs, buried anticlines, truncated wedge edges, updip sand pinchouts, fault traps, lenticular sands, and faulted noses. Extremely careful planning was required for this detailed type of seismic exploration. The seismic program was designed, to a large extent, for the type of exploration the company had planned. Since seismic techniques and procedures vary with different areas due to both surface and subsurface conditions, several different methods were tried in the field before a successful one was established.

In those areas where seismic results were poor to absent, the core drill became a valuable complementary tool to the seismograph. Where shallow mapping horizons were found in the basin, the core drill proved to be an excel-

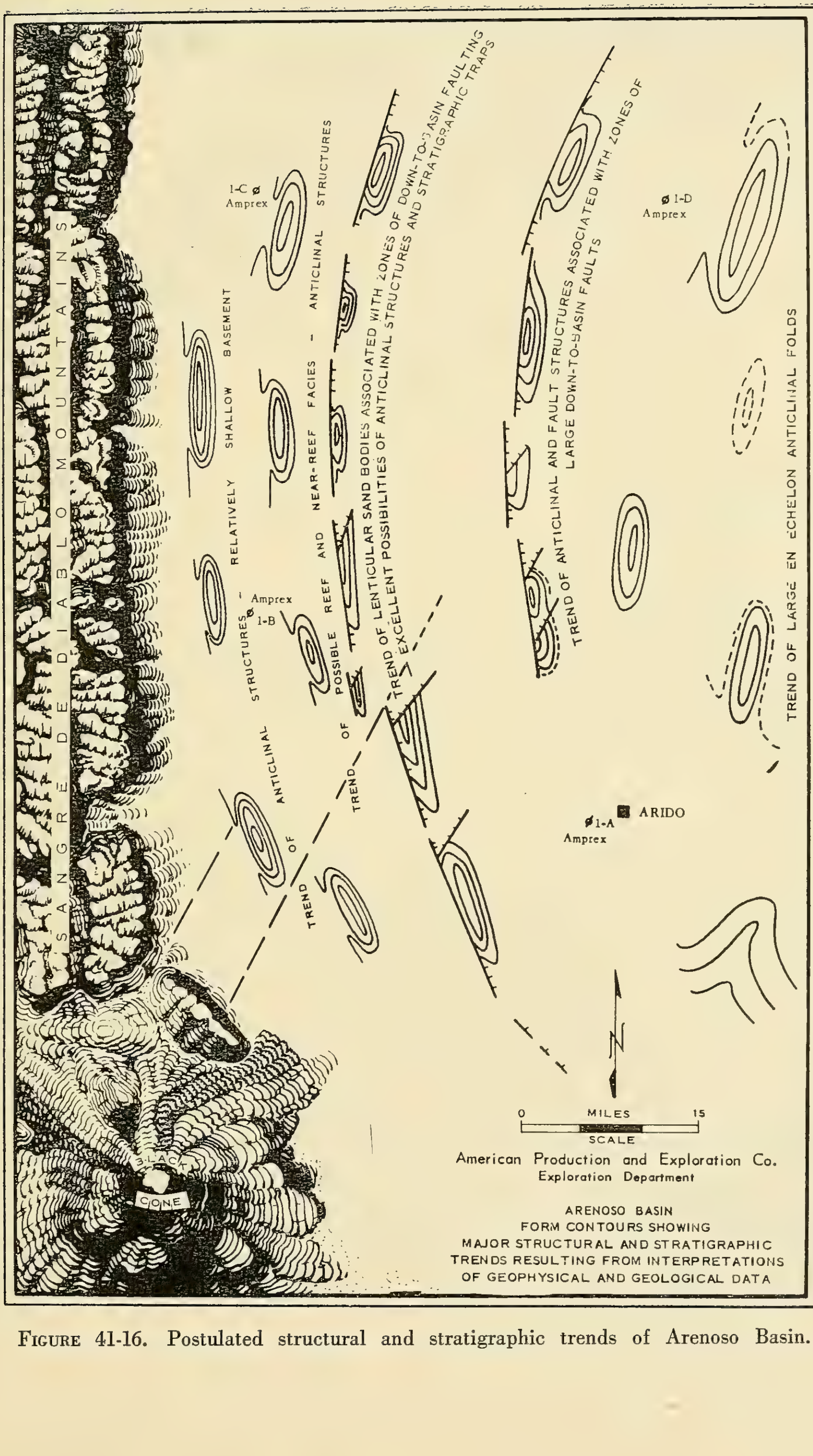


FIGURE 41-16. Postulated structural and stratigraphic trends of Arenoso Basin.

lent tool in localizing many of the earlier leads, and routine core drilling of large areas developed many new structural prospects. Amprex's geologists followed a program of first core drilling the leads and then processing large acreage blocks along the most attractive trends of the basin.

As the detailed exploration progressed, outlines of some prospects changed, new prospects were discovered and leased, some leads were eliminated, and ideas changed as additional data filled in the information obtained by the reconnaissance surveys. Significant were the changes and revisions in geological thinking as more became known of the surface and subsurface of the area. Many of the old hypotheses were strengthened, some were revised, and new ones were developed. The positions of regional structural and stratigraphic trends within the basin were modified. Their generalized position as now visualized by Amprex is shown on Figure 41-16; form contours show the structural anomalies.

The landmen continually expanded and changed their buying outlines as the areas were revised. Titlemen and lawyers began examining titles of ownership on tracts of land covering the most attractive prospects, anticipating the early wildcatting of these areas. Civil engineers were assigned the task of determining physical, political, and legal boundaries in these high-priority areas.

Wildcat Drilling Operations

Approximately 18 months after Amprex had begun its detailed exploration program, it was ready to drill some of the more attractive prospects. Almost three years had elapsed since the first company geologist had questioned the possibilities of the area. Almost six million dollars had been expended in investigating the area. The next operation to many was the most exciting phase of exploration—wildcatting.

Of the many prospects that Amprex had developed in exploring the basin, perhaps the most interesting and the most prospective was the one originally located by the drilling of the Amprex No. 1-C stratigraphic test. It will be recalled that this test found a possible reef or near-reef facies in a Devonian dolomite section which carried oil staining in the cores and cuttings. When drill-stem tested, this section actually flowed salt water with a rainbow of oil. When detailed exploration was begun, this was one of the first areas to be worked by the seismograph and also one of the first areas to be core drilled. Both seismic data and core-drill structure maps showed a well-defined anticline. The core-drill information (fig. 41-17) contoured on shallow Permian beds indicated a low-relief anticline approximately fourteen miles long having a north-south trend, while the seismic data (fig. 41-18) contoured on a horizon that was estimated to be the approximate top of the Devonian defined a major anticline having approximately the same shape and size as that of the shallow structure. Steep and erratic seismic dips occurring along the flanks of the structure, in what was correlated to be the Silurian-Devonian section, strongly

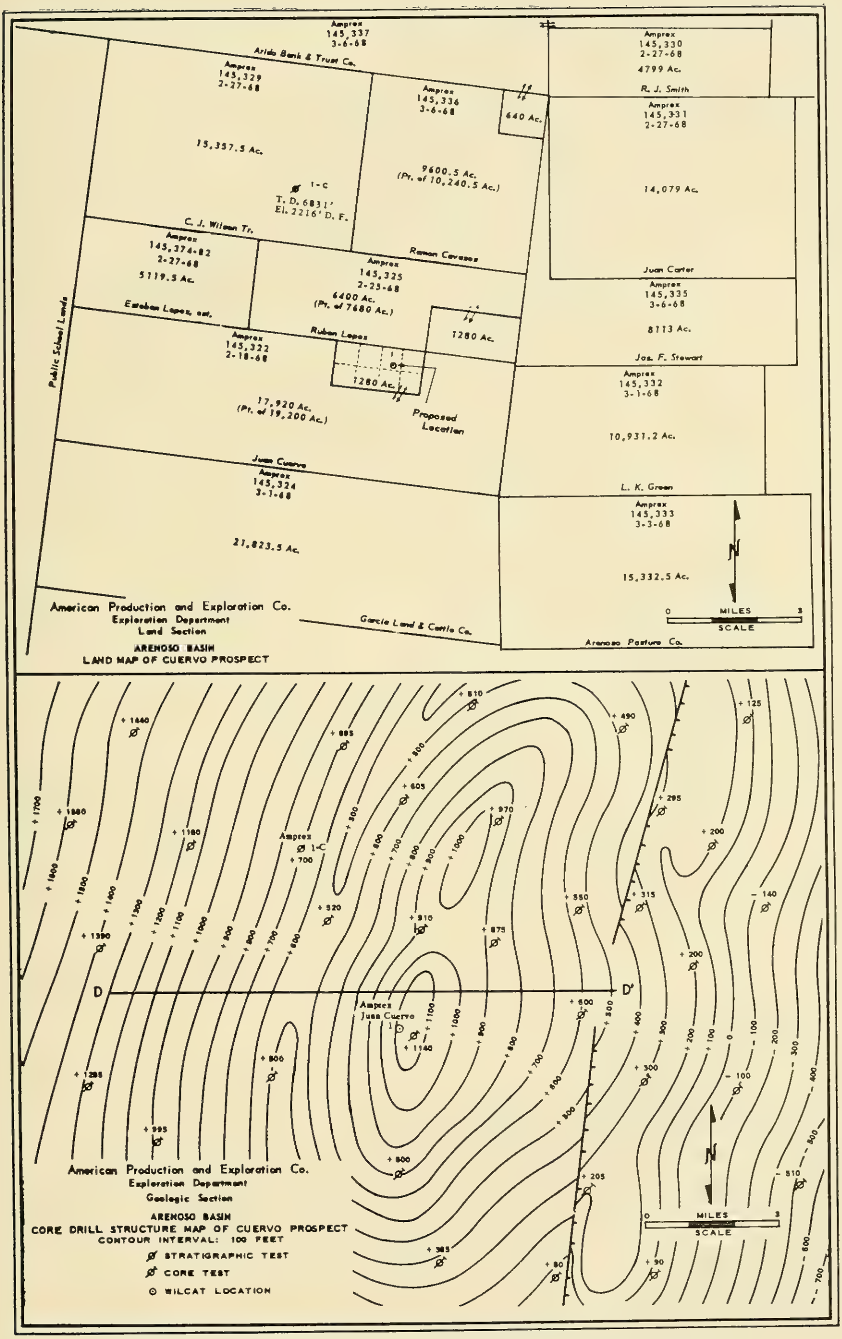


FIGURE 41-17. Land and core drill maps of Cuervo Prospect.

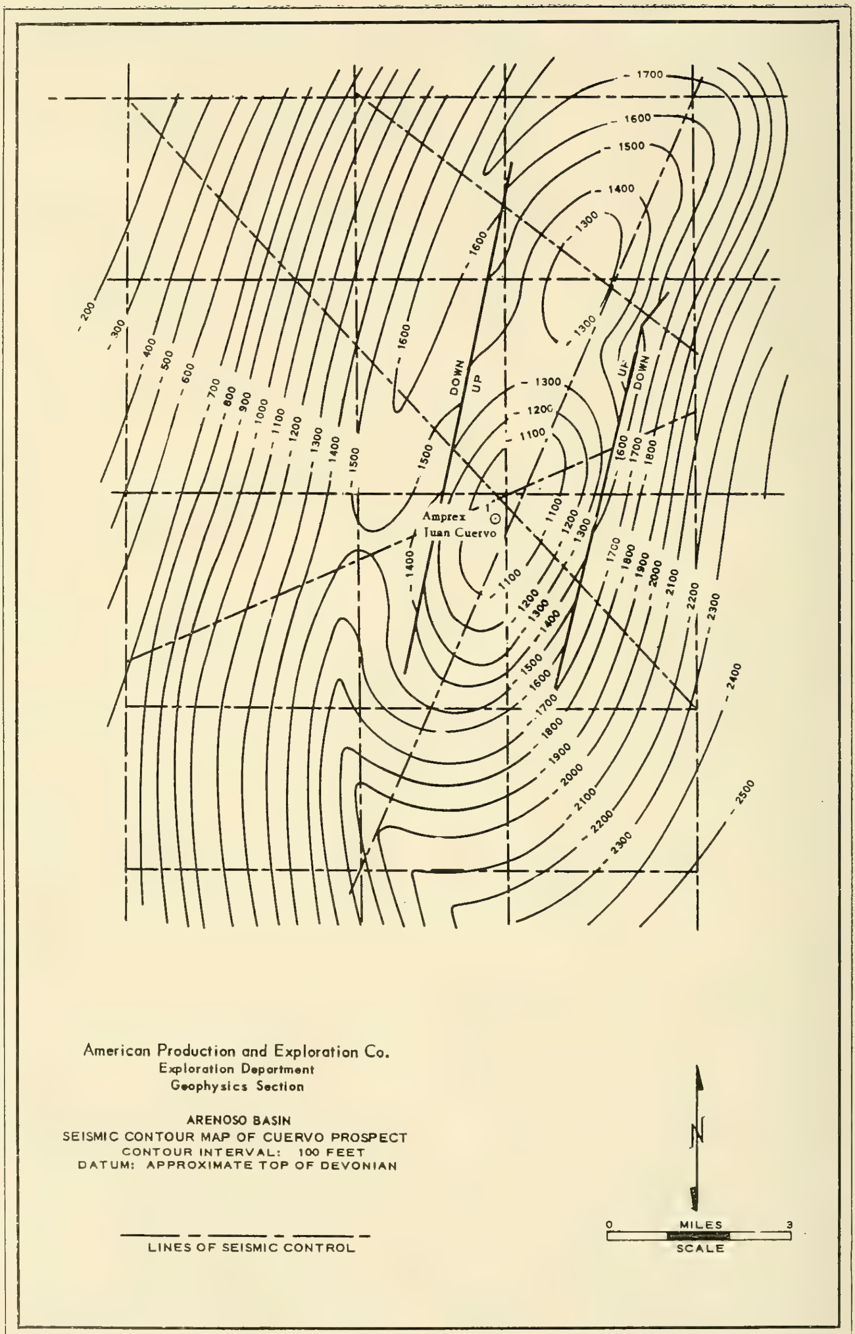


FIGURE 41-18. Seismic map of Cuervo Prospect.

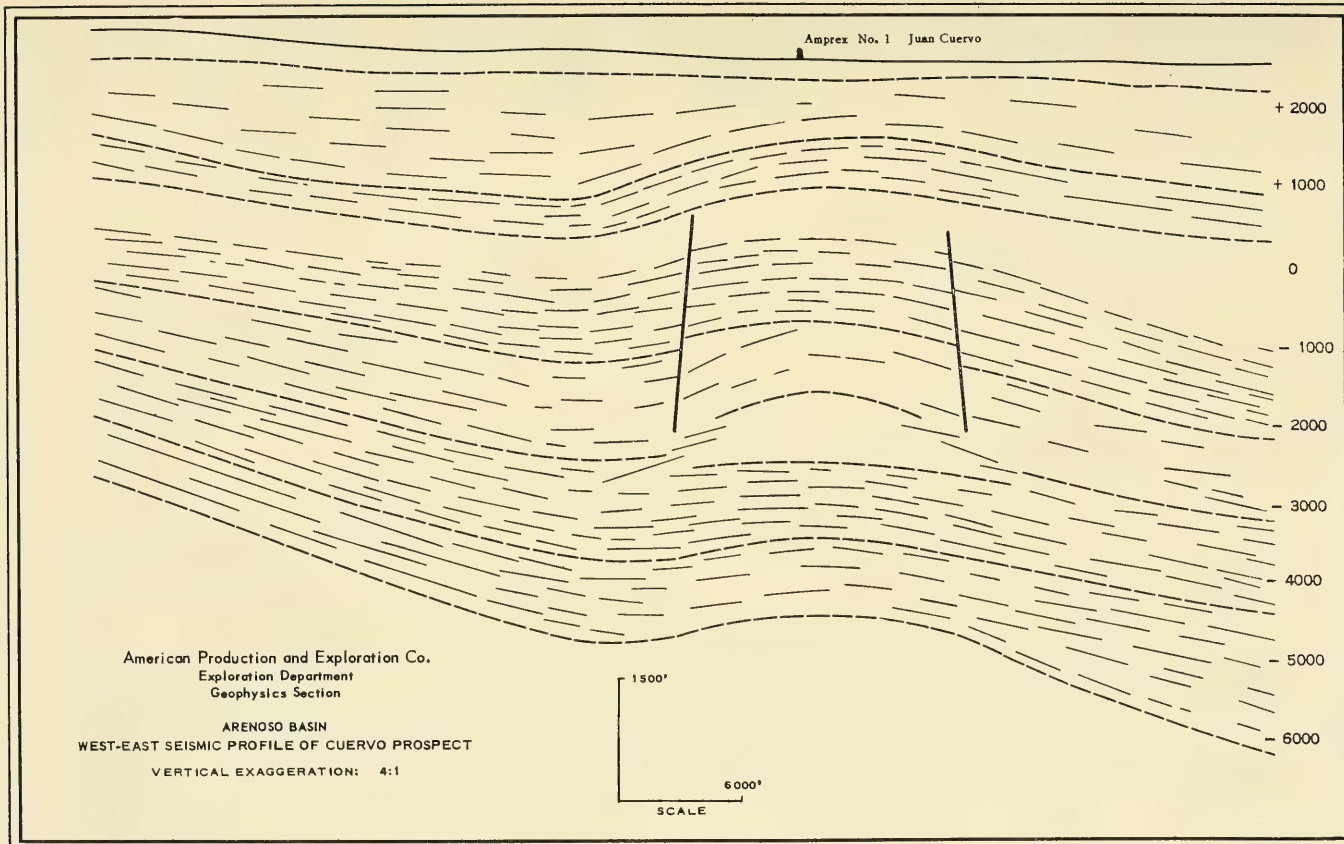


FIGURE 41-19. Generalized seismic cross section of Cuervo Prospect.

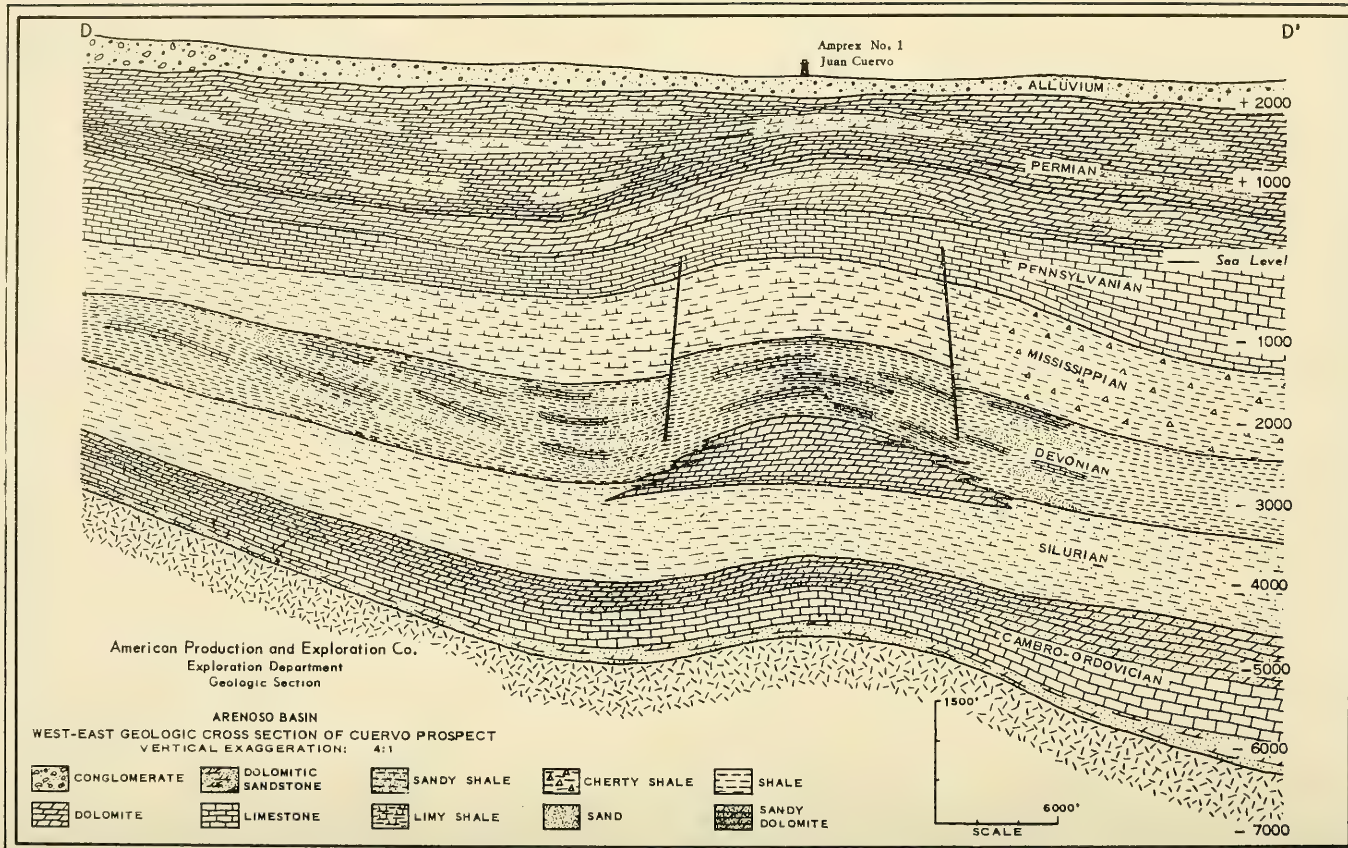


FIGURE 41-20. Geologic cross section of Cuervo Prospect.

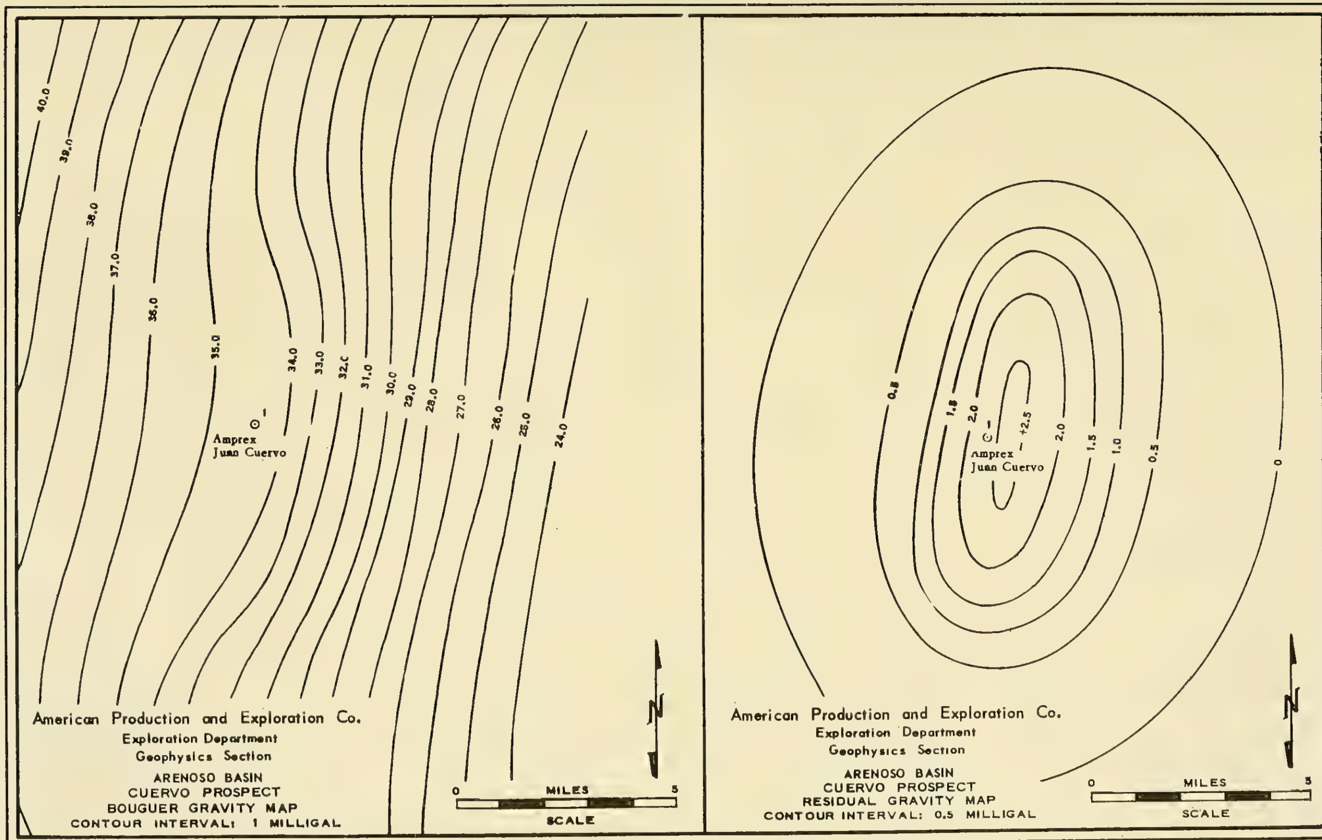


FIGURE 41-21. Gravity maps of Cuervo Prospect.

suggested that this part of the section might be reef facies over the crest of the structure. Figure 41-19 is a west-east seismic cross section of the Cuervo prospect, and Figure 41-20 is a geologic cross section of the same profile. Gravity data (fig. 41-21) indicated a gravity maximum anolmaly, and the photogeologists outlined a strong positive drainage anomaly coincident with the core-drill high. Amprex's landmen were able to lease this prospect completely (fig. 41-7), and title work of the leases covering the prospect indicated that all of the landowners had clear titles to their land. Civil engineers had surveyed the area and established physical and ownership boundaries on the ground.

Amprex's staff now filed with civil and national authorities requests for permission to drill a wildcat test in the search for oil and gas at a described location, agreeing to conform to the laws and regulations governing such operations.

Following the approval of this request to drill, Amprex's Production Department assigned from its staff petroleum engineers, drilling superintendents, mud engineers, and tool pushers to conduct the operations required in the drilling of this wildcat test. A rig was contracted from one of the larger drilling companies of the western area and trucked into the location after the civil engineers had constructed an all-weather road into the location.

From information obtained from the drilling of the No. 1-C stratigraphic test, Amprex's production group, which was in charge of the drilling operations, planned, with the assistance of the geologists, casing, coring, and logging programs to be coordinated with the instructions of the well geologist and paleontologist while the well was being drilled. The geologist on the well would instruct the production group where to core, test, and log; and, if possible and practical, the production group would execute these requests.

The drilling of a wildcat well is perhaps one of the most well-organized operations that an oil company conducts. Inasmuch as this is usually the end result of an expenditure of thousands of hours of exploration and frequently of millions of dollars, and because the success of an entire venture may hinge on information obtained from the drilling of this test, it is a poor time to economize. Cuttings and cores obtained from the bore hole must be examined and studied by qualified geologists, and electric-log surveys and gamma ray-neutron logs interpreted for lithologies and formation fluids by experts. Extensive coring and drill-stem testing must be conducted to eliminate the possibilities of overlooking potential oil and/or gas reservoirs. A logging unit, which examines the mud and the cuttings from the bore hole for minute traces of oil and gas as the well is drilled, must be employed as well as drilling-time logs to assist the geologist in locating hard and soft drilling breaks. All of these operations must be conducted contemporaneously with the drilling, for unnecessary delays during drilling operations are costly.

Utilizing all of the information available, the geologists and engineers formed a program for the drilling of the American Production & Exploration Company's No. 1 Juan Cuervo (fig. 41-22), and estimated drilling and completion costs (fig. 41-23). This wildcat was spudded, and after 1100 feet had been drilled, an electric-log survey was made. It indicated no fresh-water reservoirs below 860 feet, and surface casing was set at 1000 feet in order to protect fresh-water sands and porous limestones which were noted in the alluvial sands and gravels and uppermost Permian sands and limestones. After drilling out beneath the surface pipe, cores were taken from several sands and dolomites of the lower Permian section, which had carried faint shows of gas as noted by the mud-logging unit. However, cores, electric-log surveys, and formation tests indicated that these reservoirs were wet (carried water). A section of Pennsylvanian dense limestone 620 feet thick was topped at 1580 feet, and no shows of oil or gas were noted in the cores and cuttings. A predominantly clastic Mississippian section was reached at approximately 2200 feet, and scattered non-commercial shows of oil and gas were noted in cuttings and cores of sands and sandy shales.

At 3190 feet the driller noticed a sharp drilling break; the mud-logging unit recorded an abnormally high content of gas and oil from analyses of the drilling mud and cuttings; and the geologist found that the lithology of the cuttings had changed from shale to limestone. Cores were then taken of the interval 3195 to 3240 feet. Core recovery was approximately 70 percent and consisted of porous, oil-saturated limestone. When a formation test taken of this interval flowed 29 degree gravity oil at the rate of 18 barrels per hour through ¼-inch bottom and ⅛-inch top chokes with an estimated gas-oil ratio of 1300:1, Amprex's geologist realized that oil production had probably been established in the Arenoso Basin. The average formation flowing pressure was 1450 psi, and the shut-in formation pressure was 1580 psi. An additional 60 feet of oil-saturated limestone was cored and tested before the drill encountered shale, indicating 110 feet of limestone "pay". Core analyses and electrical surveys of the productive zone later established several dense, impermeable limestone beds, revising the productive interval to 98 feet of net effective limestone "pay". A study of the fossil content of this limestone by paleontologists indicated that it was Devonian. Three additional oil-productive limestone stringers were found in the Devonian section within the next 500 feet. Each of these pays, although relatively thin, was considered productive; combined, they had a net effective porosity thickness of 60 feet.

Shale, encountered beneath the deepest of these Devonian limestone pays, was continuously cored for the next 300 feet. While coring at 4100 feet, the driller noted an abrupt drilling break, and oil and gas began cutting the drilling mud. After 10 feet beneath this break was cored, the core barrel was pulled, and approximately 10 feet of highly porous, vugular, fractured, oil-saturated

ADOPTED DRILLING PROCEDURE

DISTRICT Arenoso Basin
FIELD Arenoso Basin wildcat
WELL No. 1 Juan Cuervo
DATE ____________

CASING

Size	Depth
9 5/8"	1000'
5 1/2"	7000'

Est. T.D. 7000'

COMPLETION:
Type: cased hole
Perf: jets 4 Shots/ft.
Acid: ____ Gal. ____ Acid

Frac: ____ Gal. ____ Oil
____
____ # Sand/Gal.

OTHER:

Surface casing to be set through all possible fresh-water sands. No abnormal pressures expected. Possible lost circulation zones in Devonian and Ordovician sections.

MUD PROGRAM
10-12# low-water loss mud. Satisfactory to carry 8-10% oil emulsion if hole conditions warrant. Lost circulation material should be added around 5500' before drilling Ordovician section.

SAMPLE PROGRAM
5' samples and drilling time from 0'-TD.
Mud-logging unit will be used from 0'-TD.

CORING PROGRAM
4 cores 1500-2000' as determined by oil shows.
16 cores 4100-4500' (Siluro-Devonian).
8 cores 5800-6000' (Cambro-Ordovician)
2 cores 6900-7000' (Precambrian).
Plus any other shows found by geologist.

DRILL-STEM TESTS
4 Permo-Pennsylvanian 1500-2000'.
16 Siluro-Devonian reef 4100-4500' or to water/oil contact.
8 Ellenburger 5800-6000' or to water/oil contact.
1 Precambrian 6800-7000'.
Plus any other shows as found by geologist.

SURVEYS
Correlation ES logs @ 1000, 2500, 4000, 5500'.
ES and microlog @ 5000' if reef indicates production.
ES, microlog, dipmeter, velocity survey @ TD.
Caliper survey if 5 1/2" csg. is to be run.
Gamma ray-neutron and collar locator after running casing.

CASING CEMENTING
9 5/8" cemented to surface with neat cement.
5 1/2" cemented up to surface casing using 8-10% gel with 200 sx. neat cement on bottom.
Use scratchers and centralizers opposite all pay sections.

FUEL: Source Butane Length line Trucked in (United Butane Co.)

WATER: Source Water Well Length line 150' Booster Pump Required No

ROAD: Length 27 miles Type 25 miles graded 2 miles surfaced Est. Completion Date 10 days after location made

LOCATION: Est. Completion Date ____________

Approved: ____________
Dist. Exploration Manager

____
Area Superintendent

Orig: Dist. Superintendent
3 cc: Area Superintendent
2 cc: Dist. Exploration Manager
1 cc: Dist. Pet. Engr.

FIGURE 41-22. Drilling procedure for Amprex No. 1 Juan Cuervo.

DRILLING COST OF AMPREX NO. 1 JUAN CUERVO

RIG COST		
$1,100/day X 85 days		= $ 93,500
CASING		
1,000' of 9 5/8"	= $ 3,360	
5,975' of 5 1/2"	= 12,600	
		= 15,960
DISTRICT SUPERVISION		
$65/day X 85 days		= 5,525
SERVICES AND SUPPLIES		
Mud and Chemicals	= $ 6,200	
Location and Roads	= 12,500	
Water Well	= 2,100	
Cementing, Logging, and Other Services	= 20,115	
Well-Head Equipment, Transportation and Supplies	= 4,955	
		= 45,870
CORING AND DRILL-STEM TESTING		
(1,200' of Cores and 45 Tests)		= 32,980
PERFORATING (50') ACIDIZING (500 GALLONS), AND 8 HOURS SWABBING TIME		= 2,575
	TOTAL	= $196,410

FIGURE 41-23. Estimated drilling and completion costs of Amprex No. 1 Juan Cuervo.

dolomite was recovered. A formation test made opposite this interval indicated excellent productivity of 37 degree gravity oil; the gas-oil ratio was approximately 1100:1; and the flowing and shut-in formation pressures were considered normal for this depth. A very slight drawdown or drop from shut-in formation pressure to flowing formation pressure indicated that the reservoir rock probably possessed excellent permeability. An additional 460 feet of permeable dolomite was continuously cored and tested before salt water was encountered. Later studies by company petrographers and paleontologists indicated that this dolomite section was reef facies of Devonian and Silurian ages.

After the reef was drilled though at 4970 feet, Silurian shales and sandy shales were drilled and cored to 5850 feet, where a hard drilling break was noted. Although the mud-logging unit had not recorded an increase in either gas or oil, the section was cored for 30 feet. Core recovery from this interval consisted of highly fractured, dense, sandy dolomite; only scattered, very faint fluorescence was noted on a few of the fracture surfaces. However, Amprex's geologist decided to make a precautionary formation test of this interval. He realized that, frequently, fractured formations which carry high-gravity oil or condensate may be flushed during drilling and coring operations. On a formation test this interval flowed gas and condensate at a calculated rate of 4.5 million cubic feet of gas and 405 barrels of 57 degree gravity condensate per day through a 1/4-inch bottom choke and a 1/8-inch top choke. Gas-condensate ratio was approximately 11,000:1. Coring and testing were continued for the next 460 feet before salt water was encountered. Drilling and coring were then continued until granite was encountered at 6801 feet. Fifty feet of fractured granite was cored; and, although no shows were noted, a precautionary test of this fractured basement was made, for Amprex geologists today were becoming aware of the potential of fractured basement reservoirs. A formation test opposite this interval flowed salt water with no trace of oil or gas. An additional 150 feet of granite was drilled and cored and, when no shows of hydrocarbons were noted, drilling was stopped.

Electric-log surveys and gamma ray-neutron logs, which were run at different stages during the drilling of the well, added detailed information to the stratigraphic section and were particularly helpful in analyzing the non-cored intervals and those intervals where core recoveries were poor. They aided in the definition of oil-water contacts and were invaluable as a continuous record of the stratigraphic section.

Casing was set to a depth of 6600 feet and cemented. After studying the results of the formation tests, the core analyses, and the different "logs", Amprex's Exploration and Production Departments decided to complete this well opposite the lower part of the Siluro-Devonian reef, although consideration was given to dually completing this well. Casing was perforated opposite an interval immediately above the oil-water contact, and the wildcat was completed as an excellent flowing oil well.

Development Program

Because Amprex had acquired leases covering all of what it thought to be the potentially productive area, it could now plan an efficient development program. Within the limits imposed by lease considerations and orders of political regulatory bodies, the locations of the development wells were planned to recover the maximum amount of oil with the natural producing mechanism while employing the widest practical well spacing.

Amprex's engineers and geologists realized that this discovery demanded the planning of a sound well-spacing program to be initiated early in field development. Proper well spacing for each of the productive reservoirs of the field could be determined only through the technical appraisal of the physical data accumulated for each reservoir, including structure, porosity, and permeability of reservoir rocks, the nature of the contained fluids, and the recovery mechanisms, i.e., dissolved-gas drive, water drive, expanding-gas drive, and gravity drainage. The well-spacing program would be designed to permit efficient secondary-recovery operations. Thus, it was necessary that the efforts of the geologists and engineers jointly be directed toward the acquisition of adequate technical evidence upon which a spacing program could be based. Amprex's group decided to employ wide initial spacing to obtain a maximum of information concerning the reservoirs, with a minimum number of wells. Early knowledge of the physical characteristics of each of the reservoirs and their individual behaviors would permit strategic location of infill wells where such wells were shown to be needed.

After a program of extensive coring, logging, and testing had been employed on an adequate number of wells to define the limits of each reservoir and the characteristics and contents of each reservoir, Amprex's engineers and production geologists would have the necessary factual data to develop the field to proper well density, and to locate each completion interval to take advantage of the most efficient driving mechanism in order to obtain high recoveries.

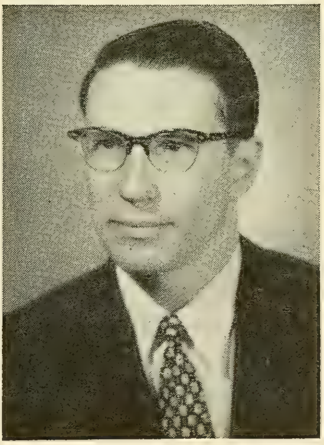
The completion of the No. 1 Juan Cuervo and the subsequent development of the Cuervo field, a name approved by the political regulatory bodies of the area, marked a new era for the Arenoso Basin. The quiet, dusty basin became a center of prosperity. Several of Amprex's competitors, through their scouting sections, had followed the geological, geophysical, and leasing activities of Amprex with considerable interest. They had scouted the drilling of the stratigraphic tests and of the No. 1 Cuervo; and, although they had no detailed information as to exactly what these tests had encountered, they were aware of the total depths of the wells and had observed the formation tests. The depths of the wells substantiated the presence of a thick sedimentary section, causing several of the companies actually to lease acreage in the basin before the No. 1 Cuervo was drilled. Such acreage acquisitions are generally referred to as protection acreage, indicating that the companies hope to be protected in the event of an important discovery. However, the moment Amprex's first formation test flowed oil, scouts and other interested individuals noticed the "black oil," and competition moved into the basin!

Within a few weeks, much of the unleased acreage in the basin had been leased. Royalty that had been trading at minimum prices now demanded competitive prices. Hotels were crowded with geologists, geophysicists, rig workers, brokers, landmen, lawyers, and promoters. Banks had a land-office business handling the transactions and wages resulting from this new industry. Farmers and ranchers who once scratched and winnowed the sands of the Arenoso for their livelihood became the fortunate. Trading centers became towns and another industry entered into the life of the valley with drilling rigs beginning to dot the landscape and with the mechanized equipment of drilling and exploring covering the roads and trails of the basin.

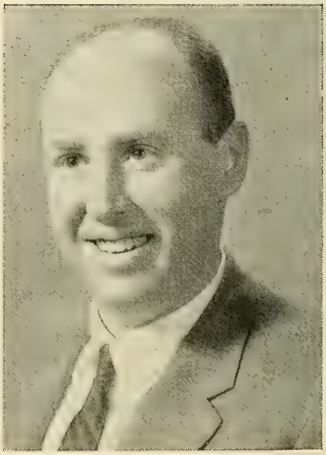
From the still valley of a few years ago, much would change. Road systems would grow over the valley floor; fields would be irrigated from the shallow fresh-water sands discovered by the drilling operations; farmers, ranchers, and merchants would prosper; and the communities of the area would progress. These changes to the valley and the profits Amprex and the people of the area and the country would realize were all the result of two of the basic steps in exploration: the curiosity and optimism of a geologist and the willingness of an oil company to take calculated risks involving large sums of capital. They were the end results of a detailed, fully integrated, scientific attack by an aggressive exploration group upon an unknown area: the Arenoso Basin.

Harold Bloom is a native of Brooklyn, New York, and received a B.S. degree in chemistry from Brooklyn College in 1935. He continued graduate study while he was employed as a teacher in the New York City schools and as a chemist at the sugar refinery of Sucrest Corporation. In 1941 he joined the U. S. Geological Survey where he worked in the topographic and photogrammetric sections. Later he was transferred to the Geochemistry and Petrology Branch of the U. S. Geological Survey, where the Geochemical Prospecting Laboratory was being formed. In 1954 he became a consultant; his principal clients were the Selco Exploration Company, Ltd., and the Dominion Gulf Company, both of Canada. Since 1955 he has been a Special Lecturer in geochemistry at the Colorado School of Mines. His publications are in the field of geochemical prospecting and deal with the development and applications of chemical tests to field exploration problems.

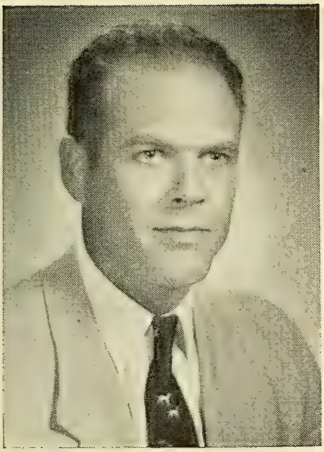
Robert B. Baum received a B.S. degree in geology from the University of Chicago in 1941. Since 1941 he has been employed by the Seismograph Service Corporation and is now Assistant Vice President and Manager of the Southern Division, Houston, Texas. He has worked in offshore Canada, offshore East Coast, Mid-Continent, Illinois-Indiana, West Texas-New Mexico, and Gulf Coast areas. He is a member of the American Association of Petroleum Geologists, Society of Exploration Geophysicists, American Association for the Advancement of Science, American Geophysical Union and other local technical societies.



W. M. Booth, a native of Oklahoma, received a B.S. degree in mechanical engineering from the University of Texas in 1947. His university training was interrupted by World War II, during which he served in the Infantry Branch of the United States Army. Upon graduation, he became affiliated with the Shell Oil Company and was engaged in various drilling activities in their Houston, Tulsa, and Calgary offices. In 1954, Mr. Booth joined Commonwealth Drilling Company and at present is in Edmonton, Canada, as Vice President of Operations.

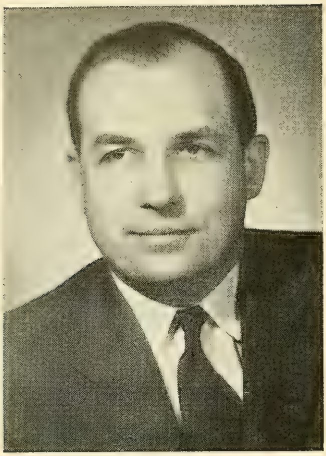


R. M. Borden is District Manager of the National Supply Company, Limited, Edmonton, Alberta, Canada, and is a graduate of Cornell University in mechanical engineering. He joined the National Supply Company in 1947, after spending a year with the United Aircraft Corporation in Hartford, Connecticut, where he was engaged in jet-engine research. Until his recent appointment he worked closely with drilling problems as they applied to the Canadian theater of operations.



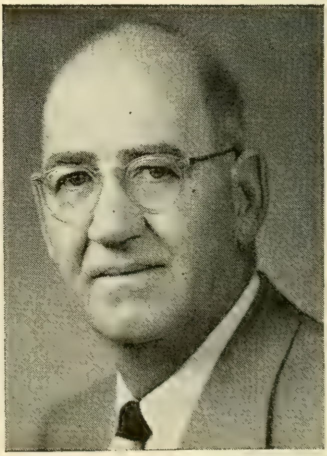
M. M. Brantly, a native of Alabama, obtained a B.S. degree in civil engineering from the Virginia Military Institute in 1943, and an M.S. degree in geology from the University of Virginia in 1954. After serving in the U. S. Marine Corps during World War II, he was employed by Drilling and Exploration Company as an engineer in Venezuela and Texas. In 1952 he terminated his services with this company and formed the Brantly Drilling Company, Inc., with headquarters in Midland, Texas.

Howard R. Breck graduated from the University of Missouri with an A.B. degree in geology in 1934. He has been employed by the Seismograph Service Corporation since 1937, and at present is Manager of their Continuous Velocity Logging Division. He served as a seismic computer from 1938 through 1941, including two years in Trinidad, B.W.I., and Venezuela. He was made a seismic party chief in 1942 and a seismic supervisor in 1945, when he returned to Venezuela for two years. Since 1947, he has resided in Tulsa, Oklahoma, and has served for various periods as supervisor dealing with equipment, personnel, and SSC's training program; seismic interpreter; seismic supervisor in the Mid-Continent Area; and manager of SSC's short-term contract department. Breck was placed in charge of Continuous Velocity Logging operations and interpretation in May 1954. In 1957 he was made an Assistant Vice President of SSC. He is a member of the Society of Exploration Geophysicists, American Association of Petroleum Geologists, Tulsa Geological Society, and Geophysical Society of Tulsa.

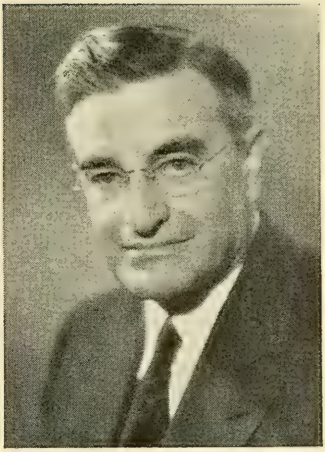


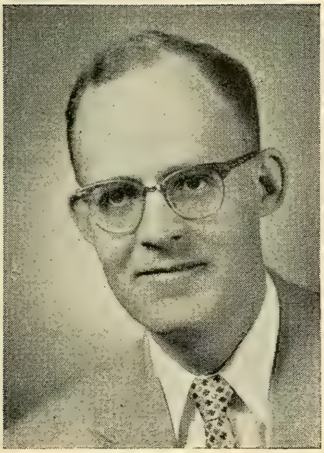
R. A. Broding was graduated from the University of Minnesota, B.S.E.E., in 1939. He joined Magnolia Petroleum Company and worked in the geophysical department as an electrical engineer. In 1942 he was a member of the Naval Ordnance Laboratory doing work on magnetic firing devices. He rejoined Magnolia Petroleum Company Field Research Laboratories in 1943 and worked on various seismic and electrical prospecting methods. As a research associate he organized and directed the well logging research group which developed magnetic and acoustic well logging instrumentation, including the continuous velocity log. Since 1953 he has been associated with Century Geophysical Corporation as Technical Vice President.

James G. Crawford attended Park College, the University of Kansas, and the University of New Mexico where he graduated with a B.S. degree in chemical engineering in 1929. He was employed by the U. S. Geological Survey from 1929 to 1946. In 1946 he organized the Chemical & Geological Laboratories, Casper, Wyoming, and is the President of that organization. He is a member of the American Association of Petroleum Geologists, the American Institute of Mining & Metallurgical Engineers, the Association of Professional Engineers of Alberta, the Wyoming Geological Association, and is a registered petroleum engineer in Wyoming. He is the author of numerous papers on the relation of waters and crude oils to geological formations, and techniques of core analysis.



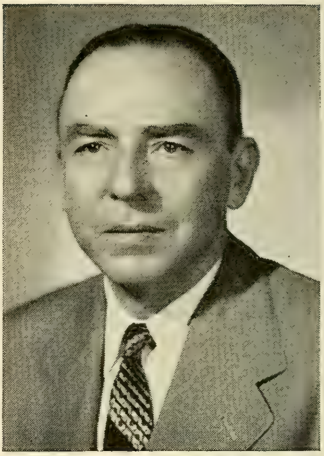
Farrington Daniels, a native of Minnesota, obtained his B.S. degree from the University of Minnesota in 1910 and his Ph.D. in chemistry from Harvard University in 1914. He taught at Worcester Polytechnic Institute, served in the Chemical Warfare Services as first lieutenant, and took a research position in nitrogen fixation in Washington. From 1920 he has been at the University of Wisconsin where he is now chairman of the Department of Chemistry. He is author or co-author of several books and many research papers in physical chemistry. His fields of research have been in chemical kinetics, photochemistry, atomic energy, and solar energy. For the past nine years, with support from the Atomic Energy Commission, he has devoted considerable time to the thermoluminescence of crystals.





John P. Dolan received a B.S. degree in mathematics and physics from the University of Denver in 1948. He was a graduate student at the University of Chicago in 1949. From 1951 to 1953 he was engaged in geophysical prospecting as an employee of the Western Geophysical Company. Since 1953 he has been a research mathematician-physicist with the Petroleum Research Corporation. His major research activity has been devoted to the interpretation of drill-stem test pressure data.

T. H. Dunn graduated from the University of Colorado in chemistry and later completed a special course in colloid chemistry at Massachusetts Institute of Technology. He was with the Midwest Refining Company in Wyoming for a few years and from 1933 has been with Stanolind Oil and Gas Company (Pan-American Petroleum Corp.) at Tulsa, first as Chief Chemist in the Producing Department, then as Research Group Supervisor in the Research Department (1943 to 1953). His principal research activities have been concerned with drilling fluids, oil field corrosion, and geochemical analysis of soils and soil gases.



Charles A. Einarsen received the Petroleum Engineering degree from Colorado School of Mines in 1947. From 1947 to 1953 he was employed by Stanolind Oil and Gas Company as petroleum engineer, drilling fluids engineer, area operations engineer, and research engineer. In 1953 he was employed by Cherokee Laboratories as Area Manager for West Texas and New Mexico. In 1957 he joined the staff of Petroleum Research Corporation as a petroleum engineer in the Hydrodynamic Analysis Department.

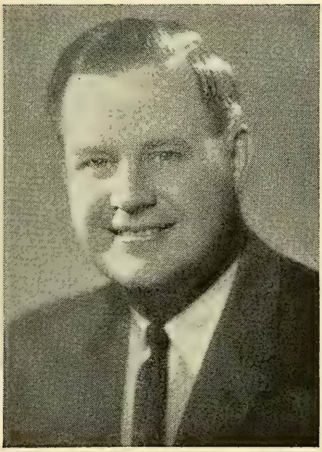
Paul E. Fitzgerald received a B.A. degree in geology from Ohio State University in 1926, and has done graduate work at the University of Michigan. Before joining Dowell Incorporated as a geologist in 1933, he was in the geological department of the Pure Oil Company. He has served Dowell in various positions in most of the oil-producing areas of the United States, Mexico, and South America. In 1953, he was appointed Manager of Public Relations for the company.

R. G. Hamilton, a native of Indiana, graduated from De Pauw University with a degree in geology in 1931. He received a master's degree and a doctorate in geology from the University of Iowa. In 1935 he joined Schlumberger Well Surveying Corporation in Houston as a logging engineer. After a year in Houston he opened an office for Schlumberger at Wharton, Texas, and in 1937 he was promoted to Oklahoma manager in Oklahoma City. He has been an instructor in well-log interpretation in courses conducted for many oil companies. In 1954 he was engaged in consulting work with oil groups in Cuba. He is a co-designer of the Arps-Hamilton Loganalyzer. In 1949 he organized Hamilton Well Log Consultants and has continued in a consulting capacity since that time. He is a member of the American Institute of Mechanical & Metallurgical Engineers, the American Association of Petroleum Geologists, the Tulsa Geological Society, and Sigma Xi.

W. P. Hasbrouck served three years in the U. S. Navy prior to attending the Colorado School of Mines where he received a degree in geophysical engineering in 1950. During the summer of 1949 he worked with Mountain Geophysical Company in Wyoming. From 1950 to 1953 he was employed by the Stanolind Oil and Gas Company on various seismograph field parties. Since 1953 he has been an instructor and a graduate student in the Department of Geophysical Engineering at the Colorado School of Mines. He is an associate member of the Society of Exploration Geophysicists and a member of the Denver Geophysical Society.

John D. Haun served four years in the U. S. Coast Guard prior to receiving an A.B. degree in geology from Berea College in 1948. He attended the University of Wyoming where he received an M.A. in 1949 and a Ph.D. in 1953. He was employed as a geologist by Stanolind Oil and Gas Company in 1951 and by Petroleum Research Corporation in 1952 where he became Vice President in charge of geological research. Since 1955 he has been teaching at the Colorado School of Mines where he is Associate Professor of Geology. He is also a member of the consulting firm of Barlow, Hammond and Haun. He is a member of the American Association of Petroleum Geologists, the Geological Society of America, Sigma Gamma Epsilon, Sigma Xi, and Phi Kappa Phi.

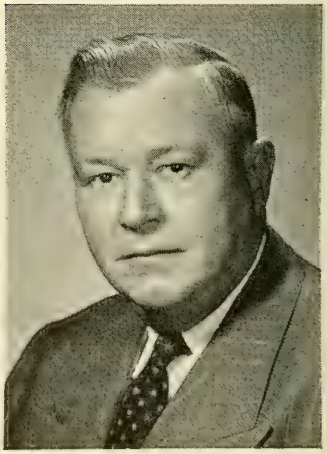
John R. Hayes, a native of Colorado, received a Geological Engineering (Geophysics) degree from the Colorado School of Mines in 1934. He was employed by Humble Oil and Refining Company in geophysics from 1934 to 1940. He served in the Corps of Engineers (Lt. Colonel), U. S. Army from 1940 to 1946. He received a Ph.D. in geology from the University of Colorado in 1950. He is Associate Professor of Geology in the Department of Geological Engineering at the Colorado School of Mines.



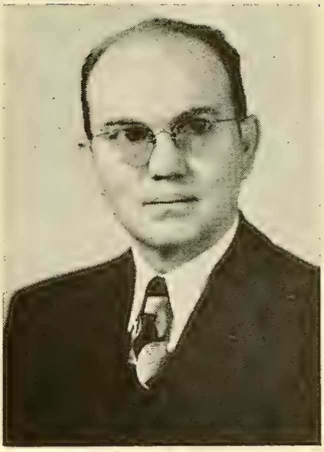
Gilman A. Hill received a Ph.B. in 1946, an M.S. (geology and geophysics) in 1947, and an M.S. (physics) in 1948 from the University of Wisconsin. From 1950 to 1951 he attended Stanford University. He was a research physicist-geologist with California Research Corporation from 1948 to 1949 and an instructor in physics at Riverside College from 1949 to 1950. He was a geological consultant from 1951 to 1953 and since that time has been President of Petroleum Research Corporation which he founded. His research has been primarily a study of petroleum entrapment under hydrodynamic conditions.

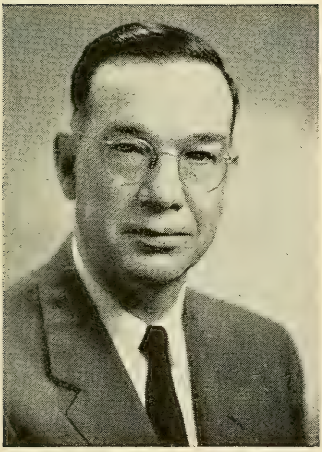
John C. Hollister attended the University of Oregon and the Colorado School of Mines where he received the Geological Engineering degree in 1932. He joined Plains Exploration Company, Denver, in 1932, as a geophysical engineer. In 1934 he became co-founder of the Heiland Research Corporation in Denver and served as Vice President and General Manager of Heiland until 1949. In 1949 he returned to Colorado School of Mines where he is Professor of Geophysics and Head of the Department of Geophysical Engineering. He is a member of Alpha Tau Omega, Sigma Gamma Epsilon, Tau Beta Pi, Society of Exploration Geophysicists, A. I. M. E., American Geophysical Union, and Denver Geophysical Society.

William S. Hoffmeister, a native of Baltimore, Maryland, received an A.B. degree from Johns Hopkins University in 1923 and a Ph.D. degree in 1926. In 1926 he was assigned to Venezuela to do paleontological work for the Lago Petroleum Corporation. In 1941 he was transferred to The Carter Oil Company to initiate paleontological work at Shreveport, Louisiana. At the end of 1946 he was transferred to the newly organized geological research section of The Carter Oil Company with headquarters in Tulsa, Oklahoma. His present title is Senior Research Geologist, in charge of the microfossil group of the Jersey Production Research Company.



Earl E. Huebotter received his B.S. degree in chemical engineering from the Rice Institute in Houston, Texas, in 1937. After graduation he was employed by Baroid as a chemical engineer and did research and development work on drilling fluids. He attended Massachusetts Institute of Technology during the summer of 1939 and 1940 to do advanced work in colloidal chemistry. He also has served as a field drilling fluid engineer in the Gulf Coast, Mid-Continent, and Pacific Coast oil fields. He is Assistant Technical Director of the Drilling Fluid Laboratories of the Baroid Division of the National Lead Company in Houston, Texas.



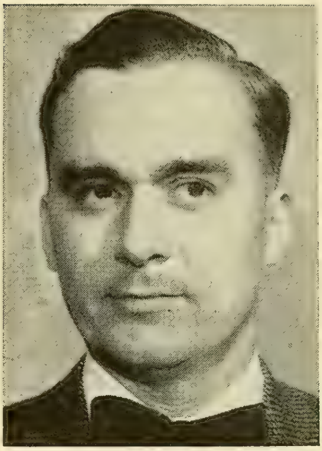


H. A. Ireland, a native of Chattanooga, Tennessee, received his A.B. degree from Ohio Wesleyan University in 1925, his M.S. degree from the University of Oklahoma in 1927, and his Ph.D. degree from the University of Chicago in 1935. He has 37 publications to his credit. He is now a professor of geology at the University of Kansas. Dr. Ireland has been over the years an ardent contributor to the problem of insoluble residues—a research investigation initiated in 1929.

George W. Johnson is a native of Indiana and received a B.A. degree from the University of Illinois and an M.A. degree from the University of Chicago. He served with the United States Air Force in Europe during World War II, and he has had practical experience in the printing, publishing, and newspaper business. He is Associate Professor of English at the Colorado School of Mines and consultant on report writing for the Petroleum Research Corporation.

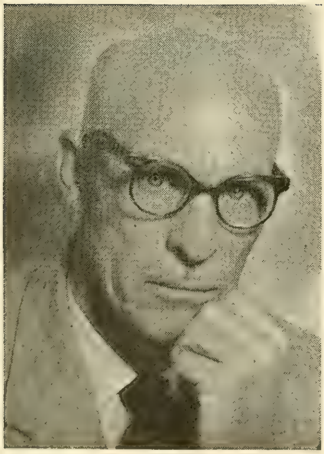
Harry C. Kent received the degree of Geological Engineer from Colorado School of Mines in 1952 and the M.S. degree in geology from Stanford University in 1953. He was employed for three years by The California Company as a geologist in Pensacola, Florida, and Harvey, Louisiana. He also worked one summer as an engineer's assistant for the Shell Oil Company in the Los Angeles Basin. Since 1956 he has been an instructor in the Department of Geological Engineering at the Colorado School of Mines. He is a member of the American Association of Petroleum Geologists, Sigma Gamma Epsilon, and Tau Beta Pi.

William M. Koch is a long-time resident of Houston, and received his B.S. degree in mechanical engineering from the Rice Institute in 1942. He started his professional career with the Douglas Aircraft Company. After an interruption for Army service, he joined the Reed Roller Bit Company in 1947. In 1953, he received an M.S. degree from the Rice Institute under a company-sponsored program, and at present is a member of the Engineering Research Department.



A. I. Levorsen, a native of Minnesota, received the Engineer of Mines degree from the University of Minnesota in 1917. He received the Doctor of Engineering degree (honorary) from the Colorado School of Mines and the D.Sc. degree (honorary) from the University of Minnesota. He was a geologist with various oil companies until 1935 and a consulting geologist from 1931 to 1934, 1935 to 1945, and 1951 to date. He was Professor of Geology and Dean of the School of Mineral Sciences at Stanford University from 1945 to 1951. He is a past president of the Geological Society of America, and of the American Association of Petroleum Geologists. He is the author of numerous papers and the book, *Geology of Petroleum,* published in 1954. He has had geological experience in several foreign countries, including Canada, Pakistan, Brazil, France, and North Africa.

L. W. LeRoy was born in Moorpark, California. He received his Geological Engineering degree from the Colorado School of Mines in 1933, and his Doctor of Geological Engineering from the same school in 1945. His geological experience has been for the most part in exploration with the Standard Oil Company of California in Africa, Indonesia, and South America. He returned to the School of Mines in 1948 and in 1953 was appointed Head of the Department of Geology. He is a member of American Association of Petroleum Geologists, Geological Society of America, The Paleontological Society, The Society of Economic Paleontologists and Mineralogists, Tau Beta Pi, and Sigma Xi.



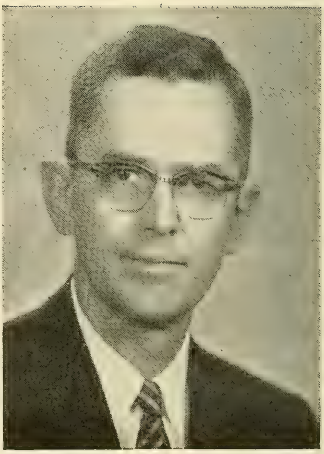
J. W. Low, a native of Colorado, graduated in geology from the University of Colorado in 1927. He has had experience as an illustrator for Carnegie Institute of Washington, mapped the topography of the Canon de Chelly National Monument, and served as a hydrographer for the State of Utah. In 1937 he became affiliated with The California Company, held many responsible positions in their Geological Division, and in 1955 was appointed Research Geologist. Mr. Low is author of *Plane Table Mapping* and *Geologic Field Methods,* both texts published by Harper and Brothers.

George B. Mangold is a registered chemical engineer and has a B.S. and an M.S. degree in chemical engineering from the University of Southern California. He worked for many years in the research laboratories of Baroid Sales on developments in drilling muds and mud-testing equipment. After a brief period in Venezuela as a mud engineer, he joined the Petroleum Engineering Associates, Inc., in Pasadena, California, where he is now Laboratory Director. He has conducted research work on drilling muds and oil-well cements and has been active in core-analysis-technique research and standardization studies and in pursuing new methods of formation logging and evaluation.

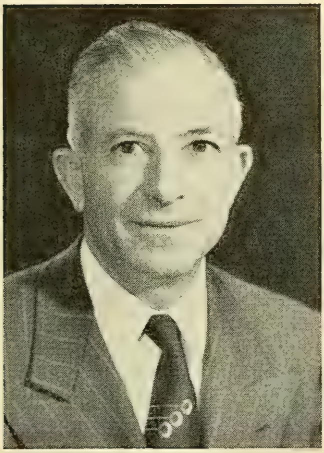
Samuel J. Martinez received his B.S. degree in chemistry from Purdue University in 1937, and his M.A. degree from Tulsa University in 1951. He was employed as a chemist by the Corn Products Refining Co. at Argo, Illinois, and later served as Explosives Chemist and Ballistician with the U. S. Ordnance Department during World War II. He joined Dowell Incorporated as Research Chemist in 1945, and was promoted to the position of Technical Editor in 1951. He has written and edited numerous technical society papers and trade journal articles, and has been responsible for the preparation and issuance of operating and instructional manuals within the company.

Hugh McClellan is a native of Oregon. After graduating from Stanford University, he spent three years in mining on the West Coast and a graduate year at Massachusetts Institute of Technology before entering the petroleum industry as a geologist in the Mid-Continent region. Of his thirty years in petroleum exploration and exploitation, he was a consultant for 15 years in Kansas, and for the past 15 years has worked in California and the Pacific Coast.

Carl A. Moore received his Ph.D. in geology from the University of Iowa in 1940. He was employed by the Standard Oil Development Company (Standard Oil Company of New Jersey) in New York City as research geologist on the occurrence of oil in sedimentary basins. In 1942 he was employed as field subsurface geologist for The Carter Oil Company in Seminole and Oklahoma City. Since 1946 he has been at the University of Oklahoma where he is Professor of Geology and Chairman of the School of Geological Engineering. He has worked primarily in subsurface geology techniques, the occurrence of oil in sedimentary basins, and the geology of South America.

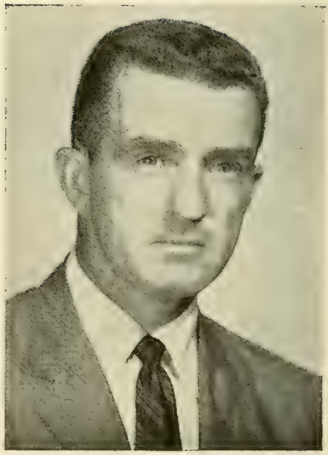


John B. O'Connor is a native of Augusta, Georgia. He served in the United States Army Signal Corps in France during World War I and has been in the oil field equipment business ever since. In addition to being President of Dresser Industries, Inc., he is a member of the Board of Directors of Dresser Industries, Inc.; President of Bovaird & Seyfang Company; President of Ideco; Chairman of the Board of Magnet Cove Barium Corporation; and President of Security Engineering Company of Canada, Ltd.



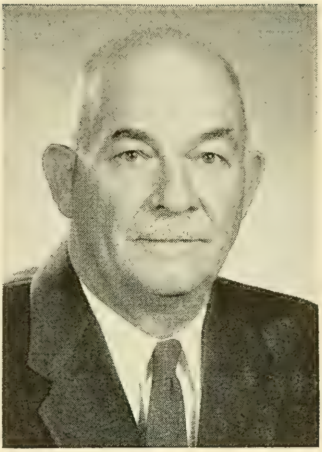
L. L. Payne graduated with a B.S. degree in mechanical engineering from Rice Institute, Houston, Texas, in 1930. He became a draftsman for Hughes Tool Company on a part-time basis in June, 1929, and in the spring of 1931 he was transferred to West Texas, where he served as a Division Engineer until January, 1940. At that time he was transferred to the home office in Houston, Texas, and until the latter part of 1943 was in charge of rock-bit product design, standardization, and development of new products. From 1943 to 1948 he was Assistant Chief Engineer, engaged in product development of rock bits, tool joints, core bits, and drill collars used in rotary drilling, as well as being responsible for administration of the department. Mr. Payne is now the Assistant Vice President of Engineering.

Paul A. Rodgers attended Texas A. and M. College where he received a B.S. degree in physics in 1934. He was employed on seismic field parties from 1934 to 1945 by the Independent Exploration Company and Seismic Explorations, Inc., respectively. From 1945 to 1949 he did magnetic and gravity surveying with the Geophysicial Exploration Company. In 1949 he joined the faculty of the Colorado School of Mines where he is now Assistant Professor of Geophysics.



Wendell H. Russell was born in Cisco, Texas. He joined the Baroid Division as a well logging engineer in January, 1946, after serving five years in the Army. He spent four years as district superintendent of the Mid-Continent district before moving to Houston as assistant to the manager of the Well Logging Department.

J. F. Sage started in the oil industry in the engineering department of the Prairie Oil and Gas Company at Ranger, Texas, in 1919. In 1921 he entered Iowa State College and studied chemical engineering. In 1925 he returned to Prairie and in 1928 he installed a geochemical laboratory for the company at Independence, Kansas. The laboratory was moved to Tulsa in 1935 after the merger of Prairie with Sinclair Oil and Gas Company. In 1952 he was transferred with the personnel of the laboratory to the Sinclair Production Research Laboratories in Tulsa. He was head of the laboratory from the time of its installation in 1928 until 1956, when he was transferred to the Exploration Division of the Sinclair Research Laboratories. He is a member of the American Petroleum Institute, the American Institute of Mining and Metallurgical Engineers, the National Association of Chemical Engineers, and the Tulsa Geological Society.



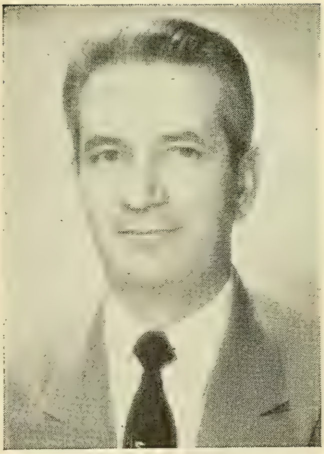
N. Cyril Schieltz, a native of Iowa, received a B.S. degree in chemical engineering from Marquette University in 1932 and a Ph.D. degree in analytical chemistry from the University of Illinois in 1938. He has been a research engineer with Gates Rubber Company, a chemist with the U. S. Department of Agriculture, and a crystallographer with the U. S. Bureau of Reclamation. He has done research work on storage batteries and the chemistry of lead, colloids and emulsions, penicillin, rubber chemistry, chemistry of starch and its derivatives, the role of pozzolans in cement, and the identification and structure of clays. At present, he is Associate Professor of Metallurgy at the Colorado School of Mines.

S. W. Schoellhorn received a B. S. degree in geological engineering from the Colorado School of Mines in 1942 and did graduate work in geophysics at the California Institute of Technology. His 14 years of experience in geology and geophysics includes field work, interpretation, instrument operation, engineering, research and development (particularly in the seismic prospecting method). In 1942 he was employed by the Seismograph Service Corporation as a trainee observer, and since that time, he has held the positions of observer, party chief, party supervisor, and at present is a senior research engineer in the Seismic Research Department. He has supervised the design and development of well logging instruments, seismic instruments and magnetic recorders. He is a member of the Society of Exploration Geophysicists and the American Association of Petroleum Geologists.

G. Frederick Shepherd graduated from Hamilton College, Clinton, N. Y., in geology, did post-graduate work at Northwestern University, 1930-1931, and at University of Chicago, 1932-1935. He was geologist with Phillips Petroleum Company, 1936-1940, and geologist with Lane-Wells Co., Houston, 1940-1941. Shepherd then was geologist with William Helis at New Orleans, 1941-1946, and consulting geologist at New Orleans, 1946-1948. From 1948-1953, he was chief geologist, General American Oil Co. of Texas, Dallas; again re-entering the consulting field in Dallas from 1953-1954. He has been a partner in the firm of Bettis and Shepherd, Dallas, since 1954. He is a member of the American Association of Petroleum Geologists, the American Institute of Mining and Metallurgical Engineers, the American Association for the Advancement of Science, and other geological societies.

Gilbert Swift, a native of Brooklyn, New York, received a B.S. degree in electrical engineering from the University of Pennsylvania in 1933, and a Professional Electrical Engineering degree in 1949. He has been employed by Well Surveys, Inc., since 1940, and is at present in charge of radioactive well-logging interpretation research. During World War II, he served as Officer in Charge, Direction-finding and Intercept Section of the Signal Corps Engineering Laboratories. Mr. Swift is the author, or co-author of a number of papers pertaining to radioactivity well logging.

Maurice Pierre Tixier was born in Clermont, France. He was graduated from the Ecole d'Arts et Metiers d'Erquelinnes (Belgium) in 1932 and from the Ecole Superieure d'Electricité in 1933. During 1934 and 1935, he worked as a field engineer for Societe de Prospection Electrique, Paris. He came to work for Schlumberger Well Surveying Corporation in 1935 and was Manager of the Rocky Mountain Area from 1941 to 1949. He is now Field Development Manager at the company headquarters in Houston, Texas. He has written many papers on technical subjects.

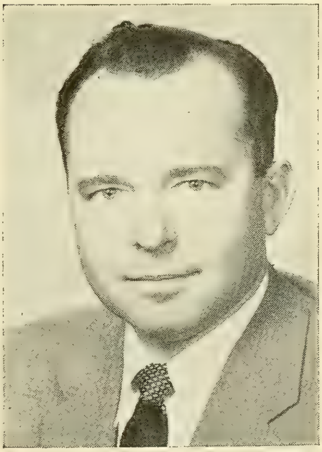


John D. Todd is a native of Beaumont, Texas. He received degrees, including the Ph.D., in geology and law from the University of Michigan. He has been a geologist and petroleum producer on the Gulf Coast for the past 25 years. He is the President-Owner of Cambe Log Library. He is the author of 15 magazine articles and is chairman of the Valuation Study Group of the Houston Geological Society. He is a member of the American Association of Petroleum Geologists, the American Institute of Mining & Metallurgical Engineers, the Texas Bar Association, and the Texas Registered Professional Engineers.

Russell B. Travis, a native of California, received a degree in geological engineering from the Colorado School of Mines in 1943, and a Ph.D. degree in geology from the University of California in 1951. He served as an officer in the U. S. Navy from 1943 to 1946. He was a geologist with the Standard Oil Company of California from 1946 to 1947 and Assistant Professor of Petrography at the University of Idaho in 1951. He was employed as a geologist with the International Petroleum Company, Ltd., Talara, Peru, from 1951 to 1953. He became Assistant Professor of Geology at the Colorado School of Mines in 1953 and in 1956 returned to Talara, Peru, with International. He is a member of the American Association of Petroleum Geologists, the Geological Society of America, the Mineralogical Society of America, and Sigma Xi. He is the author of *Classification of Rocks,* published as a Quarterly of the Colorado School of Mines.

E. A. Wendlandt is a native of San Antonio, Texas. He attended public schools in Austin, Texas. After receiving a B.A. degree in geology from the University of Texas in 1924, he was employed by Humble Oil and Refining Company as a field geologist and later became Assistant Division Geologist for the East Texas area in 1934, and Division Geologist in 1941. In 1950, he was transferred to Houston, Texas, as Assistant Chief Geologist, and has served as Chief Geologist for the Humble Company since 1955. Mr. Wendlandt is a member of the American Association of Petroleum Geologists, American Geological Institute, American Geophysical Union, American Petroleum Institute, Houston Geological Society, a life member of the East Texas Geological Society, and a fellow in the Geological Society of America, and the Texas Academy of Science. He has been author and co-author of a number of papers which have been published by the American Association of Petroleum Geologists.

Arthur H. Youmans was born in Decorah, Iowa. He graduated from Luther College in Decorah, Iowa, where he majored in mathematics, physics, and chemistry. Subsequently, he served as staff member in the Nuclear Physics Department of State University of Iowa while attending graduate school. He worked as staff physicist on OSRD project engaged in electronics research and development for military purposes during 1944 and 1945. After receiving his M.S. degree in nuclear physics in 1948, he joined the staff of Well Surveys, Inc. Since 1951, he has been supervisor of research in nuclear well logging for W.S.I.



H. L. Landua received a B.S. degree from Texas A. and M. College in 1938. He was employed as an engineer by the Humble Oil and Refining Company for 12½ years. In 1950 he became the financial officer in the firm of Ralph Low, an independent petroleum producer in Midland, Texas. In 1955 he was employed by the Oil and Gas Department of the Chemical Corn Exchange Bank, New York, where he dealt with problem of petroleum financing. In 1957 he returned to Midland as assistant to Ralph Low.

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